MONTANA WIND POWER VARIABILITY STUDY

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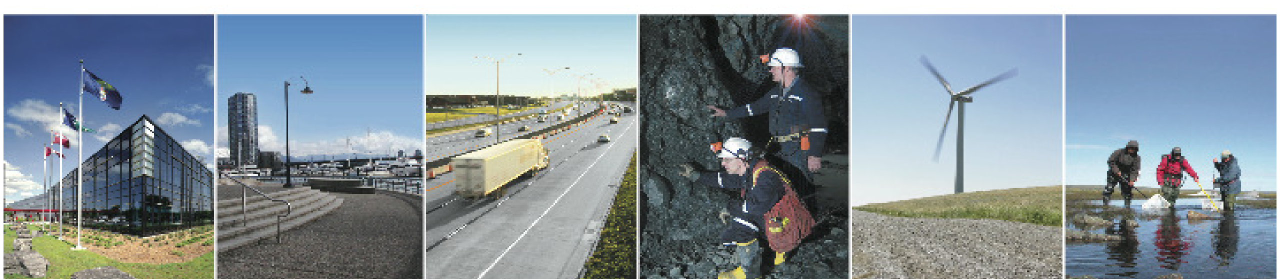

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Executive Summary

The purpose of this study was to simulate and assess wind power variability for various development scenarios in Montana and their impact on NorthWestern Energy's (NWE) electric system operation. The results include a projection of expected wind power variability resulting from various growth scenarios of the Montana wind energy industry; a demonstration of the effect on wind variability resulting from various regional dispersion scenarios; and an assessment of the impact on electric system reliability of these scenarios.

This study consisted of two major parts. The first was to apply a model that is used to simulate short-term wind power generation and fluctuation for a wind power facility (WPF). The model is based on a modified multi-turbine power curve approach; which takes into account the effect of spatial diversity on the aggregate behavior of a number of wind turbines. Several scenarios were simulated using measured local wind data collected by participating wind power developers. It was found that for three different proposed growth development scenarios with capacities of 358.5, 741, and 1450 MW that 97.5% of the 10-minute fluctuations were lower than 30, 47 and 74 MW, respectively. The maximum 10-minute fluctuations were estimated to be 112MW, 210MW, and 314MW, respectively, for the period of analysis. It was estimated that 97.5% of the 1-minute fluctuations for these scenarios were lower than 8, 11, and 20 MW, respectively. The maximum 1-minute fluctuations were estimated to be 136, 136 and 158 MW, respectively, for the period of analysis. Three scenarios with the same state-wide capacity but different degrees of regional dispersion were also studied and it was found that degree of variability was higher for scenarios with more concentrated development.

The second part of the study was to assess the impact of the wind development scenarios on the performance reliability of the NWE electric system. To do so, a system dispatch time simulator developed by the Alberta Electrical System Operator (AESO) was modified by GENIVAR to reflect the operation of the NWE system. The model was validated by comparing simulated and actual historical system performance. The impact of wind development scenarios on the electric system reliability was quantified by the North American Electric Reliability Council (NERC) Control Performance Standard 2 (CPS2). It was found that with increased wind power development, there was a decrease in CPS2 rating with some scenarios resulting in CPS2 violations. It was also found that scenarios with higher regional concentration of wind power caused lower CPS2 ratings. The merits of wind power forecasting as a mitigating measure was assessed; it was found that accurate forecasting can improve CPS2 rating. Finally, with all other system parameters held constant, additional regulating reserve range was required to maintain CPS2 compliance for some wind development scenarios. The required additional regulating range increased with increasing wind power development; also the required additional regulating range increased with increasing regional concentration of wind power.

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1 Introduction

Growth in the potential development of Wind Power Facilities (WPFs) in Montana has resulted in a need for understanding their impact on the reliability of the NorthWestern Energy (NWE) interconnected electrical system. NWE is interested in an assessment of fluctuations over periods of 10-minutes and less from geographically separated WPFs. NWE is further interested in assessing the impact of those fluctuations on the performance standards of the interconnected system using a simulation model developed in co-operation with the Alberta Electrical System Operator.

The objectives of this study were to simulate the power time series of geographically separated WPFs and to determine the wind power variability for different development scenarios. Secondly, simulated wind power generation scenarios were used to assess impact on electric system operation reliability. The reader is cautioned that wind and electrical system loads are non-stationary variables that preclude certainty in future assessments based on historical records. To model and assess wind power fluctuations and electrical system impact, the analysis procedures were organized as follows:

A preliminary analysis of wind power variation was performed for the existing WPF in Montana. The results of this analysis are provided in Section 3.

In Section 4, a model was developed to simulate 10-minute and 1-minute wind power generation time series. The model was validated by comparing simulated and measured wind power data for the existing WPF.

Simulated wind power time series for development scenarios were generated and analyzed. These results and conclusion are provided in Section 5 and Section 6 respectively.

In Section 7, a model was developed to simulate NWE's system generation dispatch. The dispatch simulation model was originally developed by and for the AESO. GENIVAR modified certain control parameters and algorithms within the simulation to reflect NWE's system operation. The model was validated by comparing simulated and historical system performance.

System dispatch time simulation for the wind development scenarios were generated and analyzed. These results and conclusions are provided in Section 8 and Section 9 respectively.

2 Data Sources and Data Period

Historical data was gathered from several sources. Independent wind power developers provided wind speed data for use in modeling wind power development scenarios. NWE provided wind power data from the existing WPFs for use in validating wind power modeling. Finally, NWE provided system load, system generation, interchange values, and operational limits for use in the system dispatch simulation model.

The goal in obtaining data was to have a synchronized period of 12 consecutive complete months from each of the data sources. The historical data sets provide a benchmark for model validations. The same historical period was then used to simulate development scenarios. Based on data availability and quality, the period selected for the study was June 1, 2006 to May 31, 2007.

3 Short-Term Wind Power Fluctuations in Montana

The characteristics of short-term (10-minute and 1-minute) wind power fluctuations were examined for existing WPFs in Montana. This analysis was performed to provide reference information in the development and validation of models of WPF operation. The models were used to simulate wind power generation and fluctuations for proposed and hypothetical WPF development.

3.1 Wind Power Data

NWE provided wind power generation data for two existing WPFs located in the Montana. The total installed capacity of the WPFs was 144 MW. The raw data consisted of power time series with 1-minute resolution. A summary of the wind power data is displayed in Table 1.

Table 1: Summary of Existing Wind Power Data

	Time Interval	Start	End	Valid Percentage (%)
WPF1	1 minute	1-Jan-06	31-Dec-07	100
WPF2	1 minute	1-Jan-06	31-Dec-07	100

3.2 Wind Power Fluctuations

The first step in the analysis was to determine the variability of the power output for the existing WPFs. A set of summary statistics of fluctuations was calculated. Fluctuations are defined as the difference in average power outputs between consecutive time intervals. The values of summary statistics were presented as a percentage of the nameplate capacities for different levels of power output. For example, in Table 2 the average 10-minute increase was 2.41% of the installed capacity when the WPFs were generating between 0% and 10% of their capacity; 3.87% when generating between 10% and 20%; and 5.42% when generating between 20% and 30%.

Table 2 summarizes the combined wind power fluctuations for the existing WPFs on a 10-minute time resolution. It was observed that the 40-50% capacity range of the WPF had the greatest annual average power increase with a value of 6.52% of the capacity; while the 60-70% capacity range had the greatest annual average decrease equal to -5.83% of capacity. The maximum standard deviation of increase was 6.83% and occurred at 40-50% of the rated capacity; the maximum standard deviation of decrease was 5.65% and occurred at 70-80% of rated capacity.

Table 3 summarizes the combined wind power fluctuations for the existing WPFs on a 1-minute time resolution. It was observed that the 50-60% capacity range of the WPF had the greatest annual average power increase with a value of 1.29% of the capacity; while the 50-60% capacity range also had the greatest annual average decrease equal to -1.24% of capacity. The maximum standard deviation of increase was 1.93% and occurred at 50-60% of the rated capacity; the maximum standard deviation of decrease was 1.73% and occurred at 50-60% of rated capacity.

Readers are cautioned that the maximum fluctuations in the tables might be caused not only by wind speed variation but also by forced or controlled outages and startups of the WPF that are unidentified in the measured wind power data.

Table 2: 10-Minute Normalized Fluctuations of 2 Existing WPFs as a Percentage of Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
2.79	2.96	9.93	-0.68	2.41	3.65	54.15	-1.28	0.98	-7.55
14.53	2.90	19.93	10.00	3.87	4.89	50.00	-2.54	2.09	-15.31
24.77	2.86	29.93	20.00	5.42	6.69	70.00	-3.90	3.14	-25.37
34.79	2.86	39.93	30.00	5.84	6.55	55.37	-4.76	4.17	-31.77
44.80	2.89	49.93	40.00	6.52	6.83	45.17	-5.29	4.78	-34.97
54.90	2.91	59.93	50.00	6.11	5.79	40.48	-5.79	5.60	-46.39
64.90	2.88	70.00	60.00	5.87	5.14	29.52	-5.83	5.64	-43.54
75.26	2.90	79.93	70.00	4.49	3.97	23.74	-5.21	5.65	-55.92
85.76	2.81	90.00	80.00	2.45	2.22	14.76	-3.27	4.17	-40.88
93.26	2.12	99.86	90.00	1.16	1.00	6.73	-1.81	2.29	-43.27

Table 3: 1-Minute Normalized Fluctuations of 2 Existing WPFs as a Percentage of Capacity[1]

Power	Sd[2].	Max	Min	Avg.[3] Inc.[4]	Sd. Inc.	Max. Inc.	Avg. Dec.[5]	Sd. Dec	Max. Dec.
2.89	2.87	10.00	0.00	0.39	0.75	24.82	-0.31	0.40	-8.15
14.54	2.90	20.00	10.00	0.70	1.20	31.64	-0.61	0.84	-18.97
24.80	2.89	30.00	20.00	0.98	1.54	29.25	-0.90	1.24	-23.11
34.85	2.88	40.00	30.00	1.14	1.73	26.47	-1.05	1.44	-20.30
44.92	2.88	50.00	40.00	1.26	1.91	35.91	-1.20	1.67	-23.97
55.02	2.92	60.00	50.00	1.29	1.93	30.12	-1.24	1.73	-23.58
64.99	2.86	70.00	60.00	1.23	1.73	24.19	-1.21	1.70	-30.45
75.32	2.89	80.00	70.00	0.99	1.40	25.99	-1.04	1.55	-23.29
85.77	2.83	90.00	80.00	0.57	0.84	14.89	-0.62	1.02	-22.38
93.24	2.10	100.00	90.00	0.28	0.39	6.49	-0.34	0.60	-20.54

4 Wind Power Modeling Methodologies and Analysis Steps

With the reference information produced in the preceding section, the next step in the study was to develop one- and ten-minute models.

4.1 10-Minute Wind Power Model

A multi-turbine power curve approach (see [1]) was adopted and modified to simulate the effects of the aggregated wind power output from a number of wind turbines within a WPF. The major model inputs were one wind speed time series and a wind turbine power curve. Other model parameters were the size of WPFs, *turbulence intensity*[6], wake/array losses, and electrical losses. Initial modeling was performed on a 10-minute resolution since this is the industry standard averaging period for wind data collection.

[1] All units in the table are % of capacity
[2] Sd. : abbreviation of standard deviation
[3] Avg. : abbreviation of average
[4] Inc. : abbreviation of increase
[5] Dec. : abbreviation of decrease
[6] Turbulence intensity: Quotient of instantaneous wind speed divided by the mean wind speed for a given period.

4.1.1 Methodologies

- *Weighted moving average wind speed time series*

It was assumed that the change in wind speed would propagate in the average wind direction with a speed similar to the average wind speed. For example, with an average wind speed of 7 m/s, a wind speed change would propagate approximately 5 km within 12 minutes. A wind speed measured near the area can be represented within the area in a time period corresponding to the traveling time of the air to pass the area. To represent the wind fluctuations over the area, the weighted moving average wind speed time series was generated from the original wind speed time series by specifying a time window. The length of the time window depended on the average wind speed of the original wind speed time series and the spatial distance of the area. The weighted moving average wind speed was defined as

$$v_j = \frac{1}{N+1} \sum_{i=j-\frac{N}{2}}^{j+\frac{N}{2}} w_{i-j+\frac{N}{2}+1} v_i ,$$

where v_j was the jth element in the weighted moving average time series, v_i was the ith element in the original time series, and w was a normalized vector of length N+1 that represents the weight for each of the original wind speeds included in each jth element of the weighted moving average. N was the number of points around the jth element to be included in each average process and defined as the nearest even integer greater than or equal to $T/\Delta t$, where T was the propagation time and Δt was the time step in the time series. The relationship between the propagation time and the distance at various average wind speeds is illustrated in Figure 1.

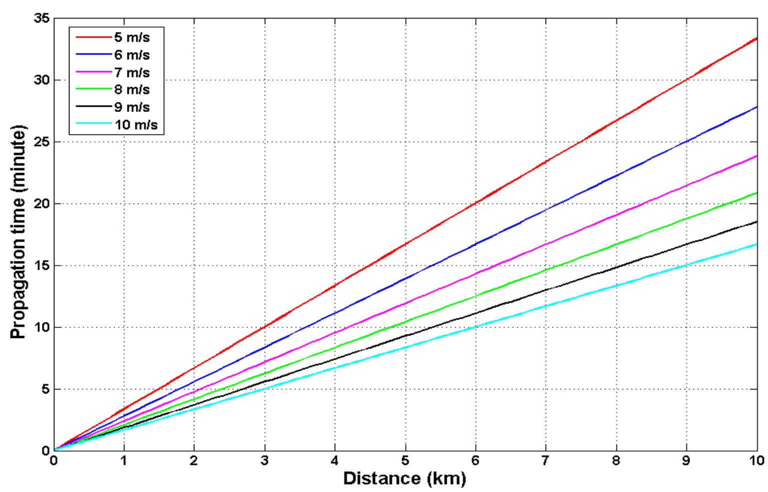

Figure 1: Relationship between the Spatial Dimension and the Propagation Time for Various Wind Speeds

- *Spatial wind speed distribution*

The modeled wind speeds at the individual wind turbines were assumed to be normally distributed at any specific time. For example, Figure 2 illustrates the frequency distribution of wind speeds measured at individual wind turbines in a WPF. The normalized standard deviation (relative to the average wind speed) of the distribution depended on the spatial dimension and turbulence intensity of the site. For example, it was proven by empirical studies (see [1]) that the normalized standard deviation was an approximate linear function of the distance when the distance was less than 50 km.

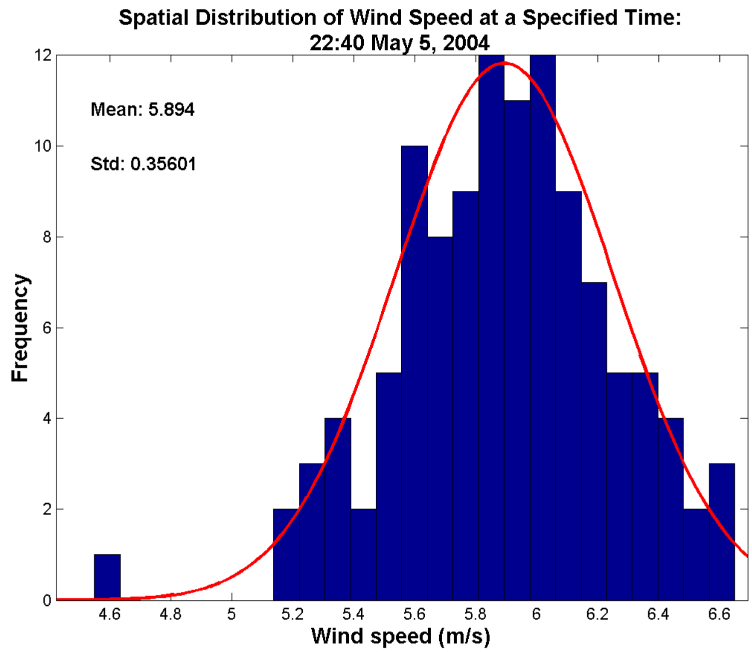

Figure 2: The Frequency Distribution of the Wind Speeds Measured at Individual Wind Turbines in a WPF

- *Multi-turbine power curves*

A multi-turbine (park) power curve was generated by applying the normal distribution of wind speeds resulting from the spatial distribution of wind turbines to a representative power curve for the WPF. Each discrete j[th] element of the multi-turbine power curve, P_j^m, was based on weighted summation of i discrete elements of the single turbine power curve as follows

$$P_j^m = \sum_i P_i^s \times p_i^s \ ,$$

where P_i^s was the i[th] element of the (discrete) single-turbine power curve and p_i^s was the probability of the spatial distribution. The normalized single-turbine power and multi-turbine power curves for a WPF are displayed in Figure 3. It can be seen that the multi-turbine power curve has a lower cut-in wind speed and a higher cut-out wind speed than the single turbine power curve. This is due to the fact that in large WPFs, when the facility average wind speed is less than the single turbine cut in speed, based on the spatial distribution of wind speed, some wind turbines can experience wind speeds higher than cut in and therefore power will be generated. Similarly, when the facility average wind speed is greater than the single turbine cut out speed, based on the spatial distribution of wind speed, some wind turbines can experience wind speeds less than cut out and therefore power will be generated. As a result, when compared to the normalized power curve of an individual turbine, a smoothing effect can be seen in the aggregate curve particularly at the cut out wind speeds. The degree of smoothing depends on the layout and size of the wind farm. The slope at cut off wind speeds will be less abrupt for larger wind farms since there will be greater variation of wind speed for the facility area.

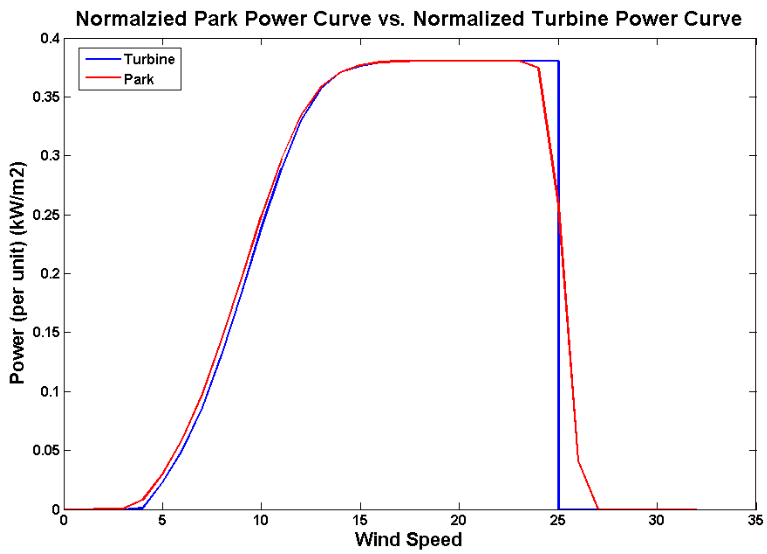

Figure 3: Normalized Single-Turbine and Multi-Turbine Power Curves for a WPF

- *Adjusting energy production*

The estimated annual energy productions for a given wind speed time series based on the two power curves in Figure 3 should equal. This was done by a minor offset adjustment of the spatial distribution.

- *Simulated wind power time series*

The multi-turbine power curve in combination with the weighted moving average wind speed time series was used to simulate a wind power output time series for a WPF.

4.1.2 Model Assumptions

- All wind turbines within a WPF were assumed to be similar, i.e., equal in size and control principle.

- The distribution of the individual wind speeds at a given time was assumed to be normally distributed around the weighted moving average wind speed. The standard deviation of the distribution was assumed to depend on wind turbulence intensity and the spatial distance of a WPF.

- Wind speed time series were assumed to be representative of meteorological towers in or near the middle of a WPF.

4.1.3 Analysis Steps

A step-by-step analysis for the methodology was illustrated below.

1. A representative dimension was specified for the area of the WPF. For future WPFs, the dimension was estimated by comparing with existing WPFs. For example, in Figure 4, the *nameplate capacity density*[7] was approximately 3 MW/km^2 for the WPFs with a nameplate capacity of 75 MW. Therefore, the area of the

[7] Nameplate capacity density is defined as the ratio of a WPF's nameplate capacity to the area of the WPF and is in the unit of MW/km^2.

WPFs was about 25 km² and the representative spatial distance was defined as the square root of the area, i.e. 5 km.

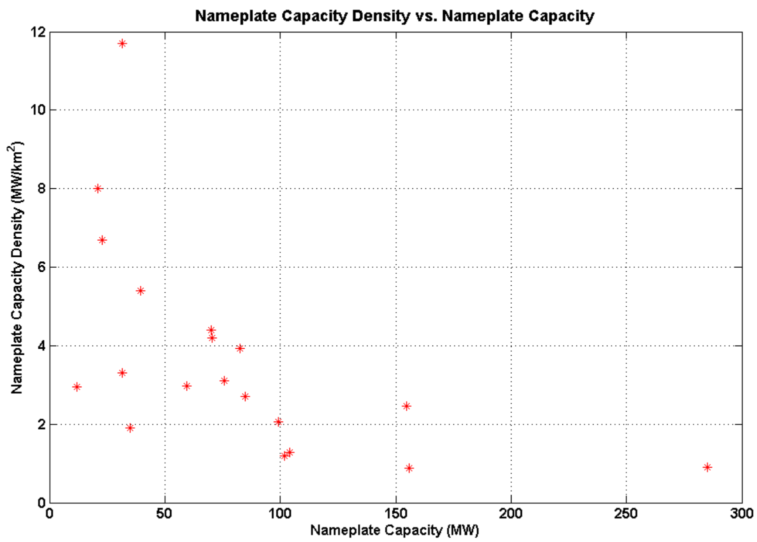

Figure 4: Scatter Plot of the Nameplate Capacity Density vs. Nameplate Capacity for Sampled Existing WPFs

2. The wind distribution was characterized in terms of the average wind speed, the Weibull fit and the turbulence intensity.

3. The wind speed time series was adjusted to the relevant hub height and a weighted moving average wind speed time series was generated.

4. The spatial wind distribution was characterized in terms of the normalized standard deviation and the actual standard deviation.

5. A single-turbine power curve was specified and adjusted to account for wake/array losses (5% of nameplate capacity) and electrical losses (2.5% of nameplate capacity).

6. A multi-turbine power curve was generated by using normally distributed variation in wind speed to adjust the single-turbine power curve.

7. The offset of the spatial wind speed distribution was adjusted so that the annual energy production from the normalized single-turbine and multi-turbine power curves were the same.

8. The wind power time series was generated by applying the multi-turbine power curve to the weighted moving average wind speed time series.

4.2 1-Minute Wind Power Model

4.2.1 Methodologies

Given a simulated 10-minute wind power time series, the 1-minute wind power was generated by linearly interpolating between two successive 10-minute wind power outputs with introduced random perturbations. The perturbations for each 10-minute interval were 10 randomly generated numbers with a normal distribution and a specified standard deviation. The standard deviation was specified as one sixth of the difference between the wind power outputs at the two successive 10-minute time points. As a result, the magnitude of variation generated in the 10-minute model can be used to restrict the magnitude of variation for the 1-minute model.

4.2.2 Model Assumptions

- The step changes were assumed to be very small for short periods (e.g. 1-minute). This was validated by actual production data. The standard deviations of 1-minute step changes were also small and suggest that the step change distribution is tightly centered about zero.

- It was assumed that the magnitude of the step change decreases as a function of the length of the time window. For example, the 1-minute step changes were on average smaller than the 10-minute step changes. This characteristic is shown clearly in the tables in Section 3.2.

4.3 Wind Power Model Validation

To validate the models, simulated and measured fluctuations for existing WPFs should be compared. Since the number of existing facilities and their pertinent data were lacking in Montana, the study did not include validation using any of the existing Montana WPFs. Extensive model validation, however, has been performed independent of this report and will be presented here.

The performance of the models was measured in terms of the magnitude and frequency of the fluctuations. The magnitudes of the fluctuations were measured as the average change at different levels of a WPF's nameplate capacity; the frequency of fluctuations was measured the percentiles of the distribution of fluctuations. To make fluctuations comparable at different capacities, the values of the above two statistics were normalized with respect to the individual WPFs' installed capacities or the total capacity for the region.

4.3.1 Validation Within a WPF

A WPF in Alberta was used to illustrate the validation. In Figure 5, the x-axis represents the wind power level relative to the WPF's installed capacity; the y-axis shows the magnitude of the fluctuations normalized with respect to the WPF's installed capacity. Figure 5 shows that the shapes of the average fluctuations were captured even though the simulated fluctuations were lower than those measured. In Figure 6, the x-axis represents percentiles of the distributions of fluctuations; the y-axis shows the fluctuations as a percentage of the WPF's installed capacity. The 97.5 percentile of measured and simulated positive fluctuations were 17.0% and 12.9% of the installed capacity, respectively; the 97.5 percentile of measured and simulated negative fluctuations were 15.5% and 12.4% the installed capacity, respectively. A short section of time series of measured and simulated 10-minute wind power generation is displayed in Figure 7. Results of the 1-minute fluctuations for the same WPF are displayed in Figure 8 and Figure 9.

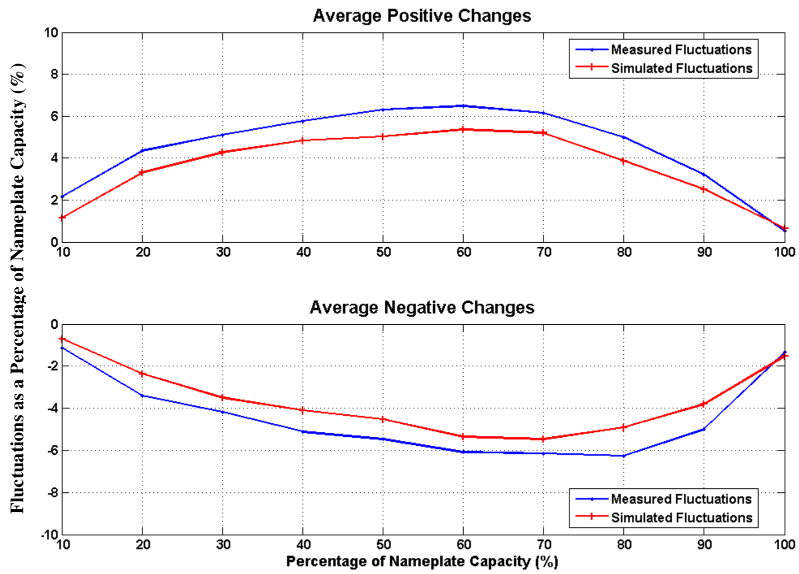

Figure 5: Comparison of Normalized Magnitudes of Measured and Simulated Power Fluctuations for a WPF (10-Minute)

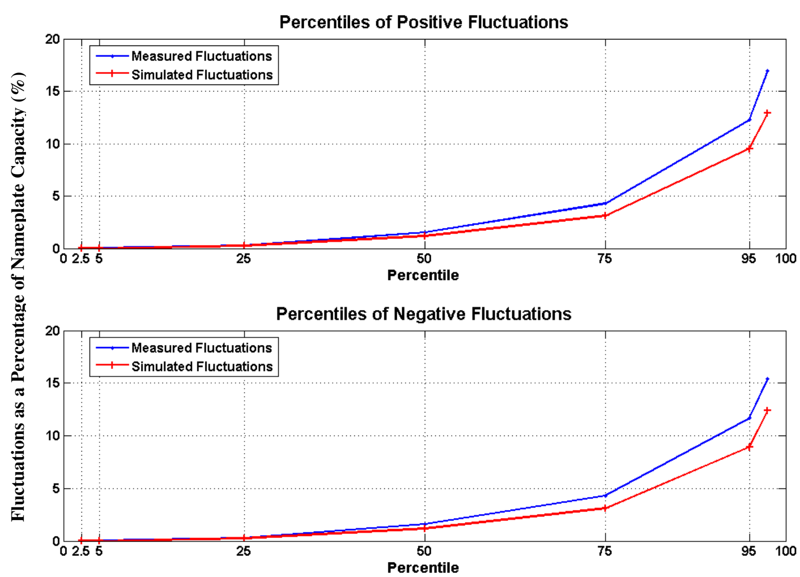

Figure 6: Comparison of Normalized Percentiles of Measured and Simulated Power Fluctuations for a WPF (10-Minute)

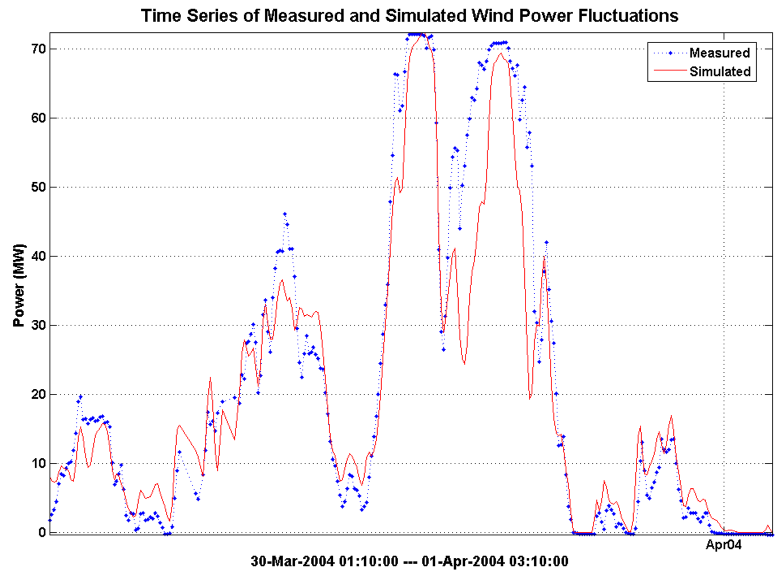

Figure 7: Comparison of Measured and Simulated Time Series for a WPF (10-Minute)

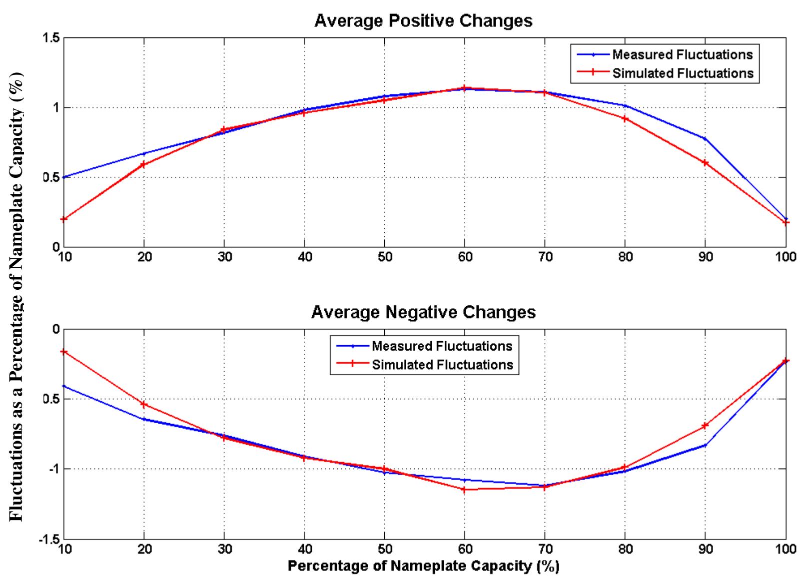

Figure 8: Comparison of Normalized Magnitudes of Measured and Simulated Power Fluctuations for a WPF (1-Minute)

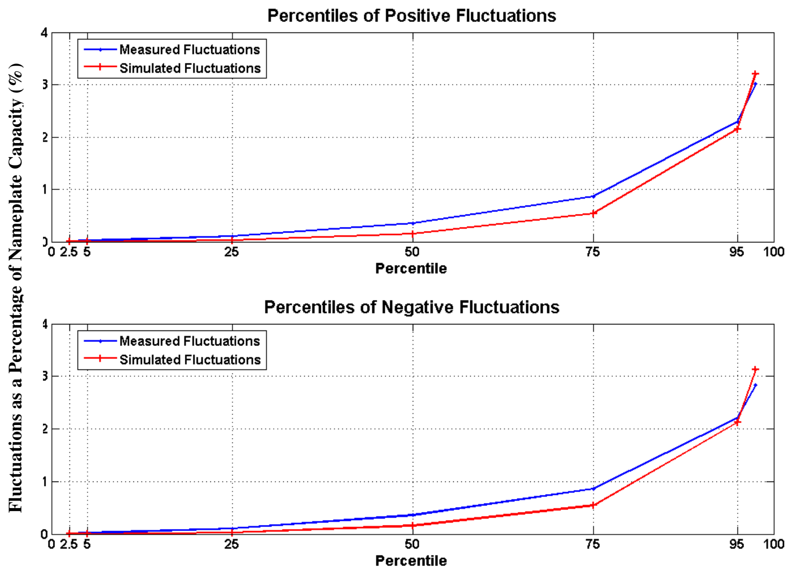

Figure 9: Comparison of Normalized Percentiles of Measured and Simulated Power Fluctuations for a WPF (1-Minute)

4.3.2 Validation Within a Region

To further validate the models, simulated and measured fluctuations for a region with several existing WPFs should be compared. Again due to the lack of availability, the study did not include validation using any of the existing Montana WPFs; however regional model validation performed independent of this report will be presented here.

Validation was performed for the benchmark scenario consisting of four existing WPFs with a combined total capacity of 223 MW. The normalized magnitude of combined fluctuations shown in Figure 10 is significantly lower than that of the fluctuations for a single WPF, as shown in Figure 5. This indicates that geographical diversity of WPFs has the effect of decreasing wind power fluctuations as a percentage of capacity. The same pattern appeared for the normalized percentiles of fluctuations and is shown in Figure 11. A short section of time series of measured and simulated 10-minute wind power generation is displayed in Figure 12. The results of 1-minute fluctuations are displayed in Figure 13 and Figure 14.

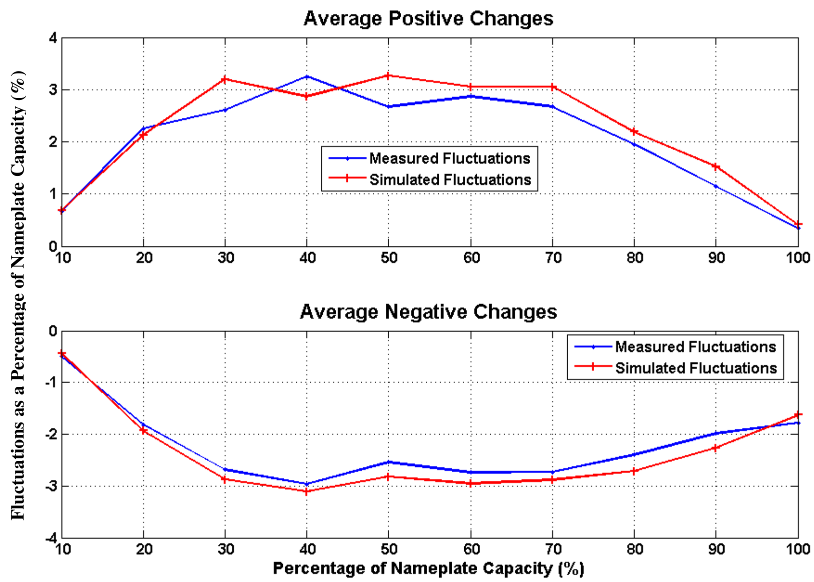

Figure 10: Comparison of Normalized Magnitudes of Measured and Simulated Power Fluctuations for the Benchmark Scenario (10-Minute)

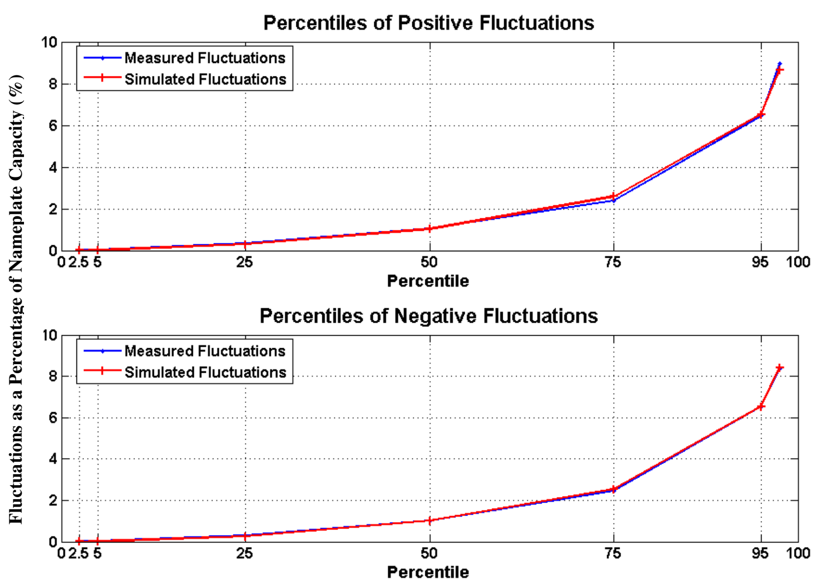

Figure 11: Comparison of Normalized Percentiles of Measured and Simulated Power Fluctuations for the Benchmark Scenario (10-Minute)

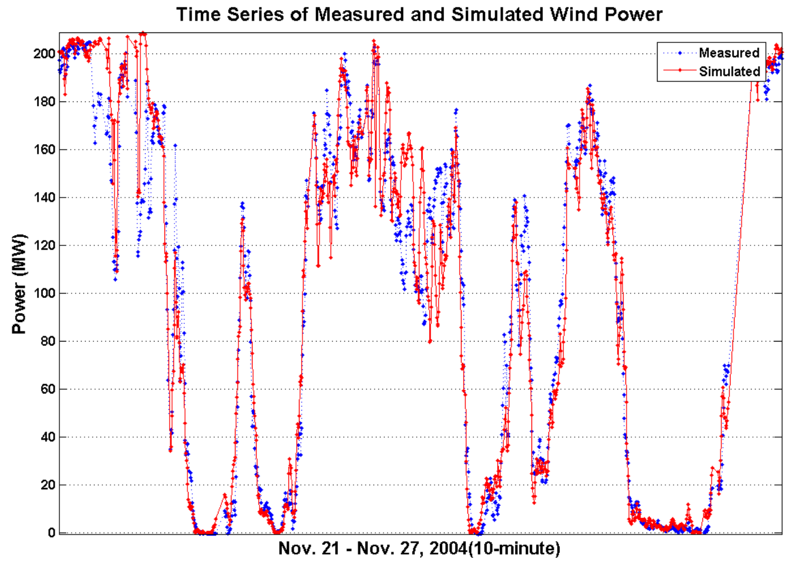

Figure 12: Comparison of Measured and Simulated Time Series for the Benchmark Scenario (10-Minute)

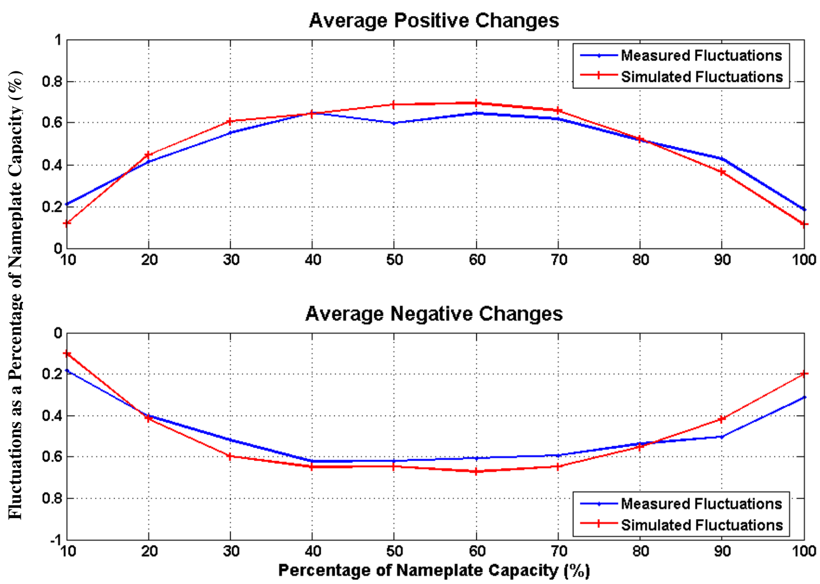

Figure 13: Comparison of Normalized Magnitudes of Measured and Simulated Power Fluctuations for the Benchmark Scenario (1-Minute)

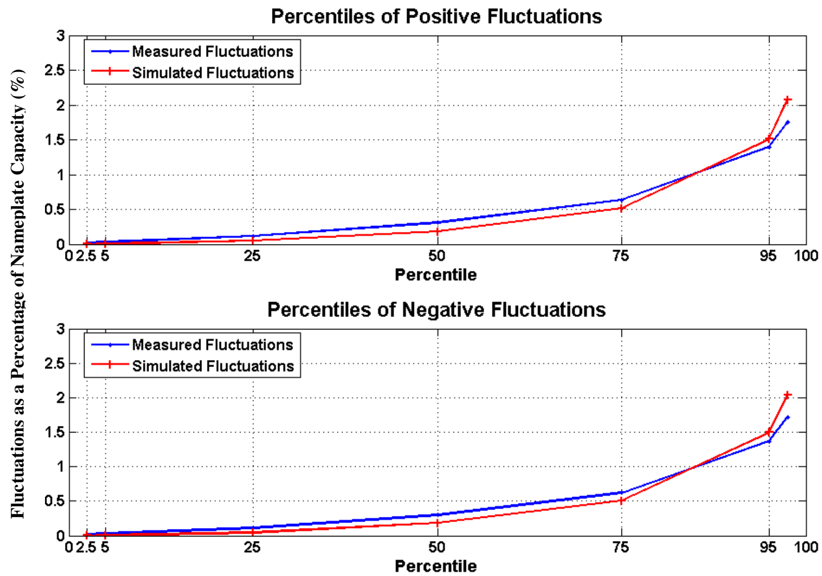

Figure 14: Comparison of Normalized Percentiles of Measured and Simulated Power Fluctuations for the Benchmark Scenario (1-Minute)

4.4 Wind Power Sensitivity Analysis

The effects of varying model parameters have been assessed: WPF dimensions, turbulence intensity, air density, wake/array losses, and electrical losses. To examine the effects of a particular model parameter, the values of other parameters must be fixed. This limits the effect of interaction between parameters and isolates the effects of the variable parameter.

4.4.1 The Effect of Wind Turbine Power Curves

It was found that the proposed model is sensitive to the choice of the single-turbine power curve. The higher the rated power of the power curve, the lower the wind power variability for a fixed nameplate capacity. These results are illustrated in Figure 15. The reduction in wind power variability may be related to either the rated power of the wind turbine power curve or the effect of spatial separation of wind turbines since the two parameters are interrelated.

- Fixed model inputs: Area dimension = 10 kilometer; turbulence intensity = 10%; nameplate capacity = 100 MW; air density = 1.14 kg/m^3.
- Varied model input: Vestas 90 (V90), Vestas 80 (V80), GE77, and Enercon70.

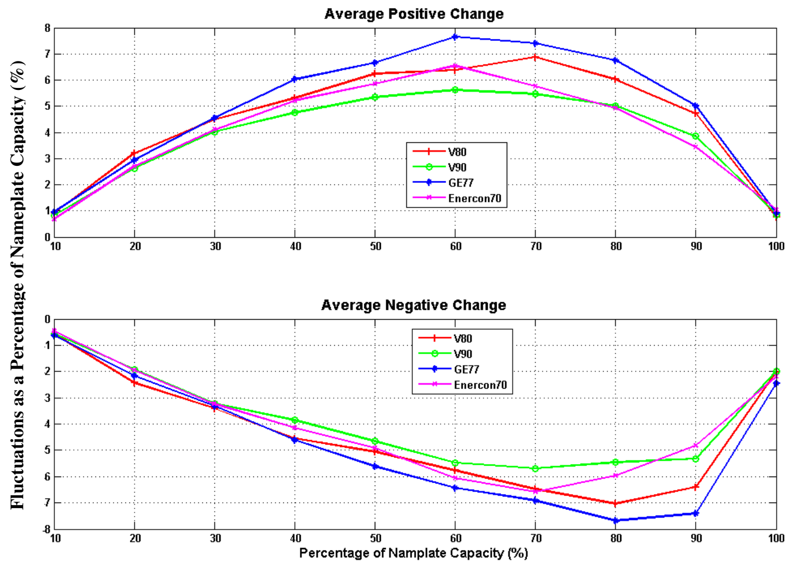

Figure 15: Sensitivity Analysis on the Effect of Wind Turbine Power Curves

4.4.2 The Effect of WPF Size

The model was found to be sensitive to the effect of spatial separation of wind turbines. The wind power variability decreases when the WPF dimension increases. To assess the effect of the size of WPFs in realistic scenarios, nameplate capacity density was used. Rather than specifying the dimensions of the WPF directly, the representative values of nameplate capacity density were first specified and then the corresponding WPF's dimensions were calculated as inputs to the model. Existing or planned WPFs' nameplate capacity densities are plotted against their nameplate capacities in Figure 4. Further, to control the interaction between nameplate capacity and area dimension, the effect of area dimension was assessed at different levels of nameplate capacity: 200 MW, 100 MW, 70 MW, and 30 MW. The analysis output is illustrated in Figure 16 through Figure 18.

Nameplate capacity = 200 MW

- Fixed model inputs: turbulence intensity = 10%; turbine model = V90; air density =1.14 kg/m^3;
- Varied model input: size = 5.8, 7.1, 8.2, 10 and 14.9 kilometers, which correspond to approximate nameplate capacity densities of 6, 4, 3, 2, and 0.9 MW/km^2, respectively.

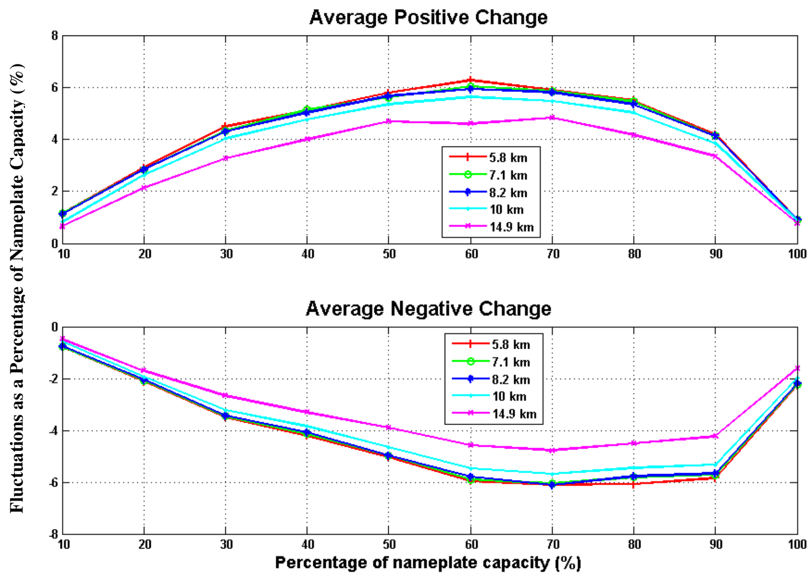

Figure 16: Sensitivity Analysis on the Effect of Area Dimension with a 200 MW Nameplate Capacity

Nameplate capacity = 100 MW

- Fixed model inputs: turbulence intensity = 10%; turbine model = V90; air density =1.14 kg/m^3;
- Varied model input: size = 4.1, 5, 5.8, 7.1 and 10.5 kilometers, which correspond to approximate nameplate capacity densities of 6, 4, 3, 2, and 0.9 MW/km^2, respectively.

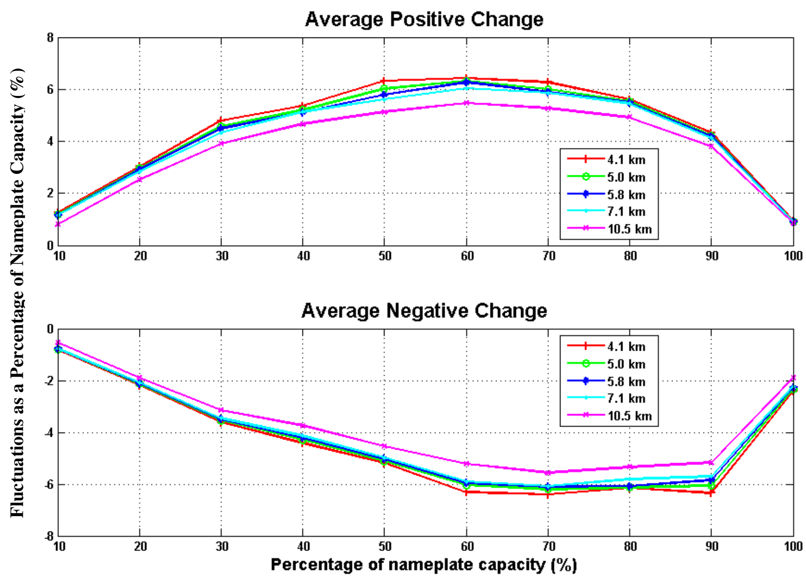

Figure 17: Sensitivity Analysis on the Effect of Area Dimension with a 100 MW Nameplate Capacity

Nameplate capacity = 70 MW

- Fixed model inputs: turbulence intensity = 10%; turbine model = V90; air density =1.14 kg/m^3;
- Varied model input: size = 3.4, 4.2, 4.8, 5.9 and 8.8 kilometers, which correspond to approximate nameplate capacity densities of 6, 4, 3, 2, and 0.9 MW/km^2, respectively.

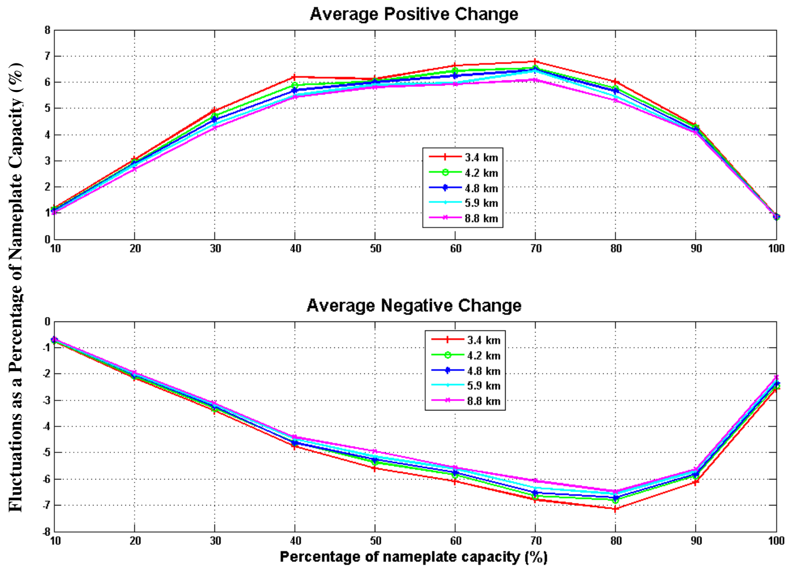

Figure 18: Sensitivity Analysis on the Effect of Area Dimension with a 70 MW Nameplate Capacity

Nameplate capacity = 30 MW

- Fixed model inputs: turbulence intensity = 10%; turbine model = V90; air density =1.14 kg/m[3];
- Varied model input: size = 2.2, 2.7, 3.2, 3.9 and 5.8 kilometers, which correspond to approximate nameplate capacity densities of 6, 4, 2, 3 and 0.9 MW/km[2], respectively.

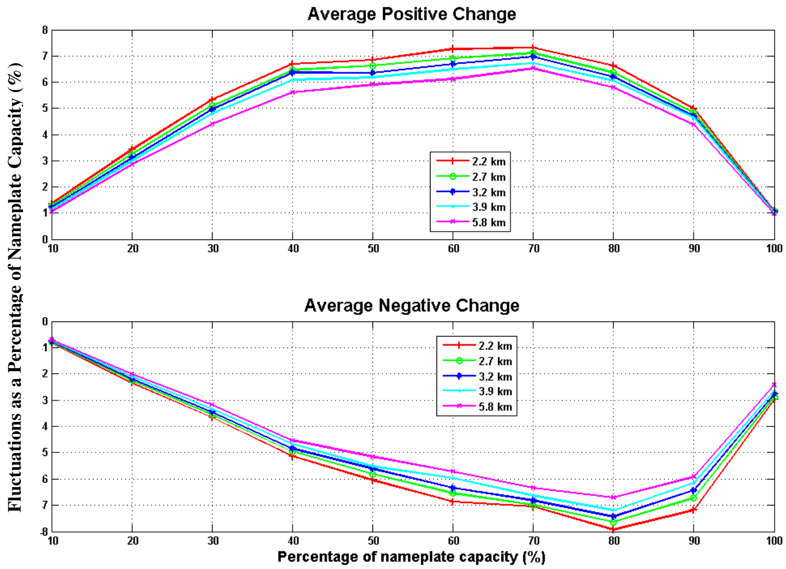

Figure 19: Sensitivity Analysis on the Effect of Area Dimension with a 30 MW Nameplate Capacity

4.4.3 The Effect of Turbulence Intensity

The model is not sensitive to turbulence intensity since the same wind speed time series was used for modeling each wind turbine in a given WPF. As a result, the real local turbulence intensity was not represented. The analysis output is illustrated in Figure 20.

- Fixed model inputs: Area dimension = 10 kilometers; turbine model = V90; air density =1.14 kg/m^3; nameplate capacity = 100 MW

- Varied model input: turbulence intensity = 5%, 10%, 15%, and 20%.

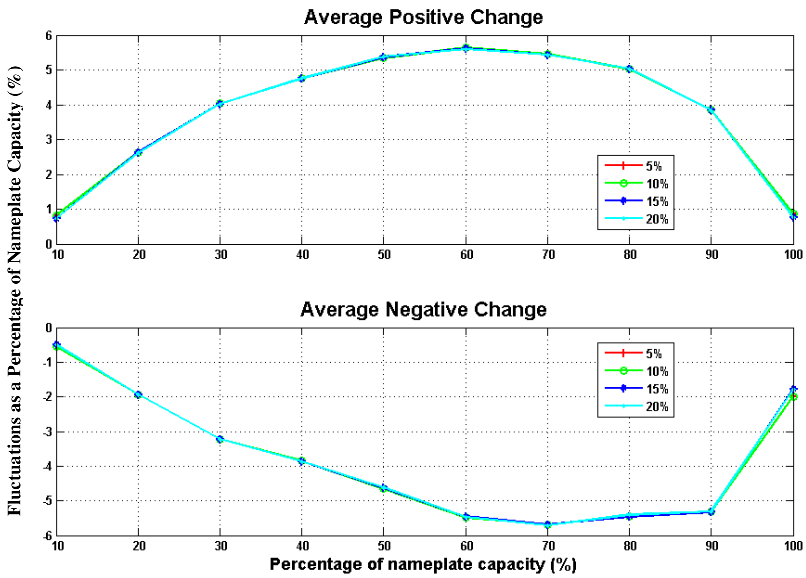

Figure 20: Sensitivity Analysis on the Effect of Turbulence Intensity

4.4.4 The Effect of Air Density

It was found that the higher the air density, the greater the wind power variability. This analysis was performed by specifying the wind turbine power curves at different air densities. The analysis output is illustrated in Figure 21.

- Fixed model inputs: Area dimension = 10 kilometers; turbulence intensity = 10%; turbine model = V90; nameplate capacity = 100 MW

- Varied model input: air density = 0.97, 1.06, 1.12, 1.18 and 1.27 kg/m³

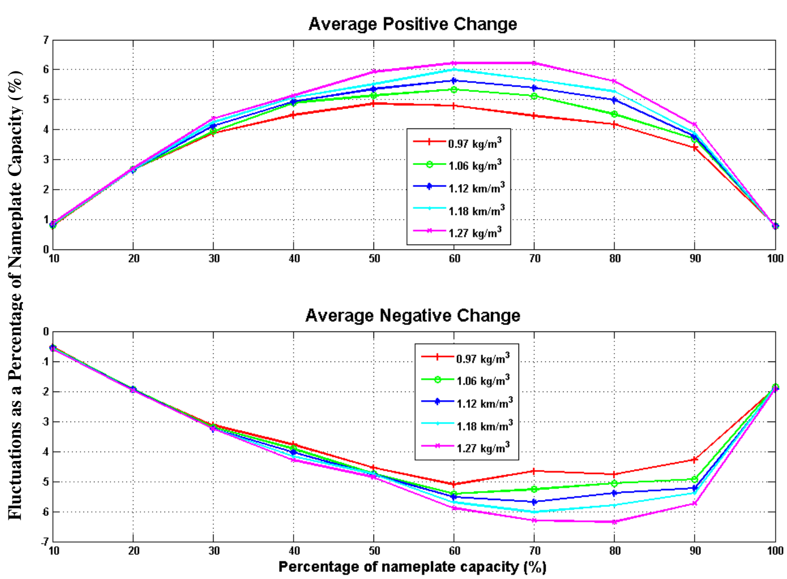

Figure 21: Sensitivity Analysis on the Effect of Air Density

4.4.5 The Effect of Wake/Array Loss

It was found that wake/array loss is not a significant parameter of the model. Comparison of a WPF's power curve with and without the effect of wake/array loss is illustrated in Figure 22. The analysis output is displayed in Figure 23.

- Fixed model inputs: Area dimension = 3.4 kilometers; turbulence intensity = 10%; turbine model = V90; air density =1.14 kg/m³; nameplate capacity = 51 MW

- Varied model input: V90 power curve with and without wake/array loss

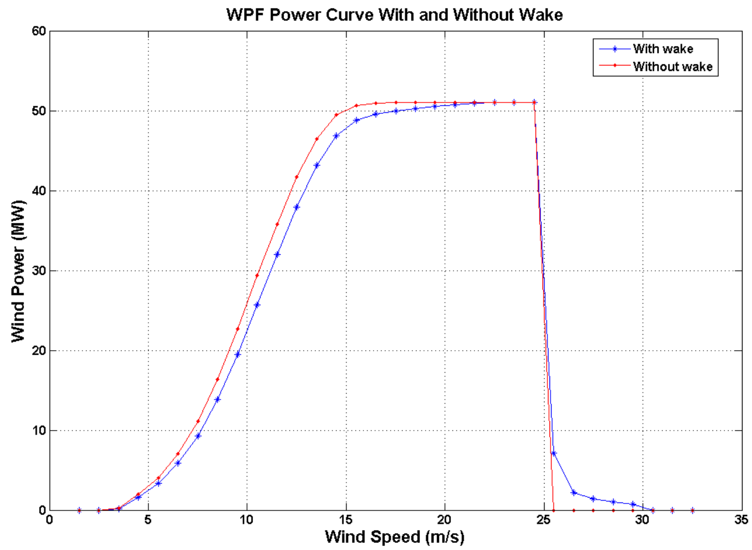

Figure 22: Power Curves With and Without Wake/Array Loss

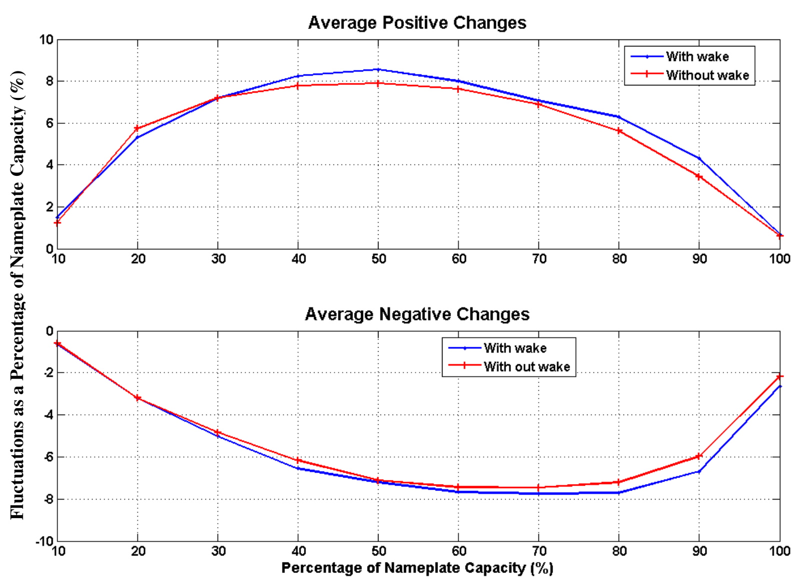

Figure 23: Sensitivity Analysis on the Effect of Wake/Array Loss

5 Simulation of Existing and Future Wind Power Scenarios

Using the validated models described in the preceding sections, wind power generation time series were simulated for existing and potential future WPFs. The simulated wind power generation time series were then combined for the potential WPF development scenarios.

5.1 Scenario Description

5.1.1 Existing and Proposed Development Scenarios

One existing scenario (Scenario A) and three proposed development scenarios (Scenarios B, C and D) were studied. Proposed development scenarios were grouped according to approximate commissioning dates envisioned by the wind developers. The three proposed development scenarios were presented based on proposed total state WPF capacities of 358.5, 741, and 1450 MW. The design of the proposed development scenarios did not consider regional separation as was addressed in the project scoping.

Scenario A has two existing WPFs and a total nameplate capacity of 144 MW. Wind power data for the two facilities was provided by NorthWestern Energy.

Scenario B has two existing and three proposed WPFs and a total nameplate capacity of 358.5 MW. For the three proposed WPFs, wind meteorological data has been collected from three local monitoring towers. The quality of wind data is summarized in Table 15 and Table 16 of Appendix 1. The data sources in this scenario have a greater degree of geographical dispersion[8] than Scenario A.

There are two existing and seven proposed WPFs in Scenario C. The total nameplate capacity is 741 MW. For the seven proposed WPFs, wind meteorological data has been collected from six local monitoring towers. The quality of wind data is summarized in Table 17 and Table 18 of Appendix 1. The data sources in this scenario have a greater degree of geographical dispersion than Scenario B.

There are two existing and twelve proposed WPFs in Scenario D. The total nameplate capacity is 1450 MW. For the twelve proposed WPFs, wind meteorological data has been collected from eight local monitoring towers. The quality of wind data is summarized in Table 19 and Table 20 of Appendix 1. . The data sources in this scenario have a lesser degree of geographical dispersion than Scenario C.

5.1.2 Hypothetical Geospatial Diversity Development Scenarios

In addition to three proposed scenarios, three hypothetical scenarios (Scenarios E, F and G) were modeled to observe the effect of regional diversity. All hypothetical development scenarios had a total state-wide capacity of 1450 MW distributed over four regions. Each scenario, however, had different distribution of power so as to compare evenly distributed development with progressively more concentrated development. For all three hypothetical scenarios, wind meteorological data was collected from 8 local monitoring towers. The quality of wind data is summarized in Table 21 through Table 26 of the Appendix 1.

Scenario E has power equally distributed; 362.5MW in each of the four regions. Scenario F has power concentrated in two regions; 625 MW in two regions and 100 MW in two regions. Scenario G has power concentrated in one region; 1150 MW in one region and 100 MW in three regions. Table 4 summarizes the power distribution by region the Scenarios E, F, and G.

[8] The degree of geographical dispersion is quantified by the standard deviation of the percentage capacity by region assuming four regions within Montana

Table 4: Regional Power Distribution of 3Hypothetical Scenarios (MW)

Region	Scenario E	Scenario F	Scenario G
Region 1	362.5	625	100
Region 2	362.5	625	1150
Region 3	362.5	100	100
Region 4	362.5	100	100
TOTAL	1450	1450	1450

5.2 Magnitudes and Percentiles of the Simulated Wind Power Fluctuations

5.2.1 Existing and Proposed Development Scenarios

The top percentiles of simulated 10-minute and 1-minute fluctuations for the existing and proposed scenarios are summarized in Table 5 and Table 6. These values are independent of the direction (positive and negative) of fluctuation. It can be seen that the magnitude of the simulated wind power fluctuations increase with increasing total capacity in the state. For example, in Table 5, the maximum of the simulated 10-minute fluctuations are 103MW, 112MW, 210MW, and 314MW for Scenarios A, B, C, and D, respectively. In Table 6, the maximum of the simulated 1-minute fluctuations are 53MW, 136MW, 136MW, and 158MW for Scenarios A, B, C, and D, respectively. The simulated wind power fluctuations as a percentage of the nameplate capacity, however, decrease with increasing capacity. For example, referring to Table 5 again, the maximum of the simulated 10-minute fluctuations are 71.5%, 31.3%, 28.3%, and 21.6% of the total capacities for Scenarios A, B, C and D respectively. In Table 6, the maximum of the simulated 1-minute fluctuations are 36.7%, 37.9%, 18.4%, and 10.9% of the total capacities for Scenarios A, B, C, and D respectively. Furthermore, it can be seen that extreme fluctuations are rare. For example, Table 5 shows less than 0.5% of the 10-minute fluctuations exceed 37MW, 48MW, 73MW, and 124MW for Scenarios A, B, C, and D respectively. Similarly, Table 6 shows less than 0.5% of the 10-minute fluctuations exceed 11MW, 13MW, 20MW, and 35MW for Scenarios A, B, C, and D respectively.

Table 5: Percentiles of Simulated 10-Minute Fluctuations for Scenarios A, B, C, and D (MW)

	95.0%	97.5%	99.5%	Maximum
Scenario A (144 MW)	15.30	20.70	36.18	102.90
Scenario B (358.5 MW)	23.79	30.24	47.74	112.06
Scenario C (741 MW)	36.79	46.80	72.77	209.80
Scenario D (1450 MW)	58.84	73.93	123.69	313.85

Table 6: Percentiles of Simulated 1-Minute Fluctuations for Scenarios A, B, C, and D (MW)

	95.0%	97.5%	99.5%	Maximum
Scenario A (144 MW)	3.57	5.24	10.31	52.79
Scenario B (358.5 MW)	5.80	7.58	12.72	136.00
Scenario C (741 MW)	8.43	11.26	19.24	136.08
Scenario D (1450 MW)	14.37	19.56	34.62	158.36

Comparisons of the magnitudes and percentiles of simulated 10-minute fluctuations for the various scenarios are displayed in Figure 24 and Figure 25. Comparisons of the normalized magnitudes and percentiles of simulated 10-minute fluctuations are displayed in Figure 26 and Figure 27. Complete statistics for the normalized magnitudes of 10-minute fluctuations are show in Table 27 through Table 29 of Appendix A. The frequency distributions of power for 10-minute time series are shown in Table 39 through Table 42 of Appendix A.

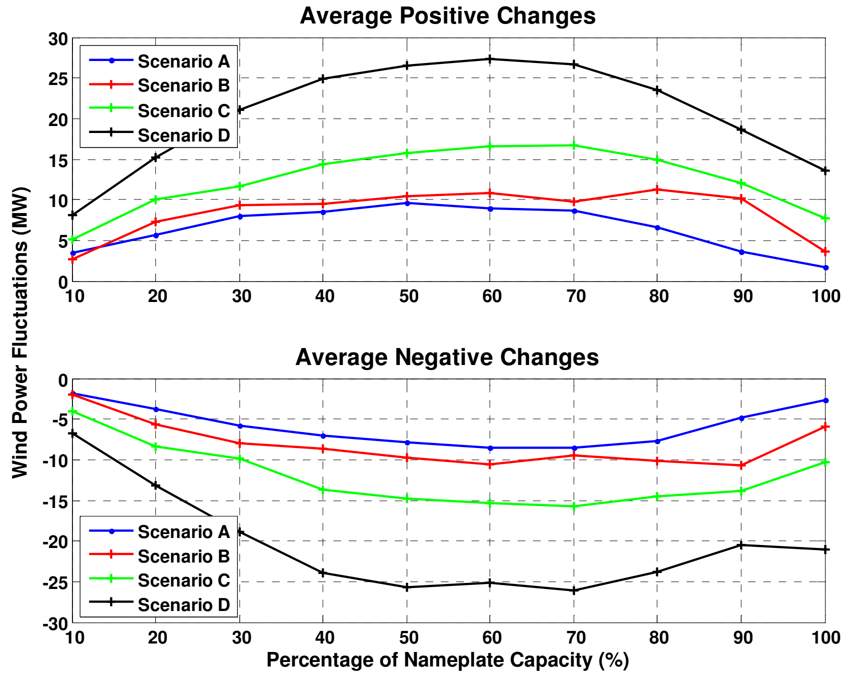

Figure 24: Comparison of the Magnitudes of Simulated Fluctuations for Scenarios A, B, C, and D (10-Minute)

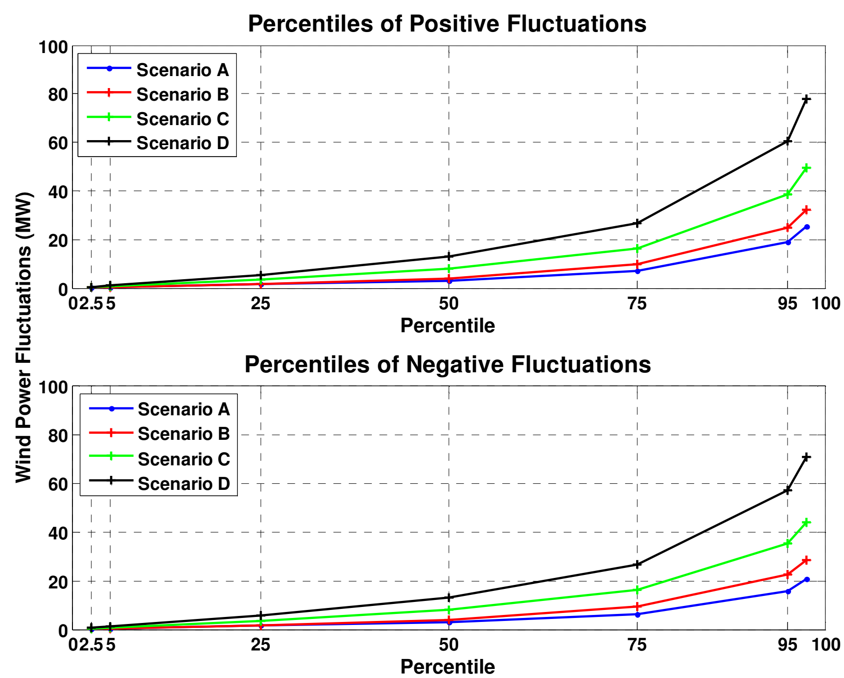

Figure 25: Comparison of the Percentiles of Simulated Fluctuations for Scenarios A, B, C, and D (10-Minute)

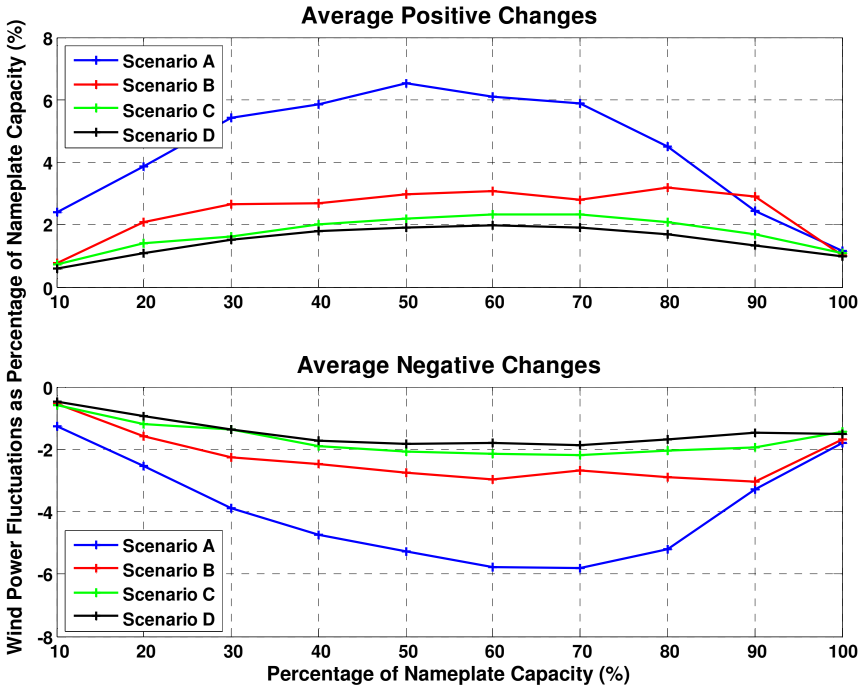

Figure 26: Comparison of the Normalized Magnitudes of Simulated Fluctuations for Scenarios A, B, C, and D (10-Minute)

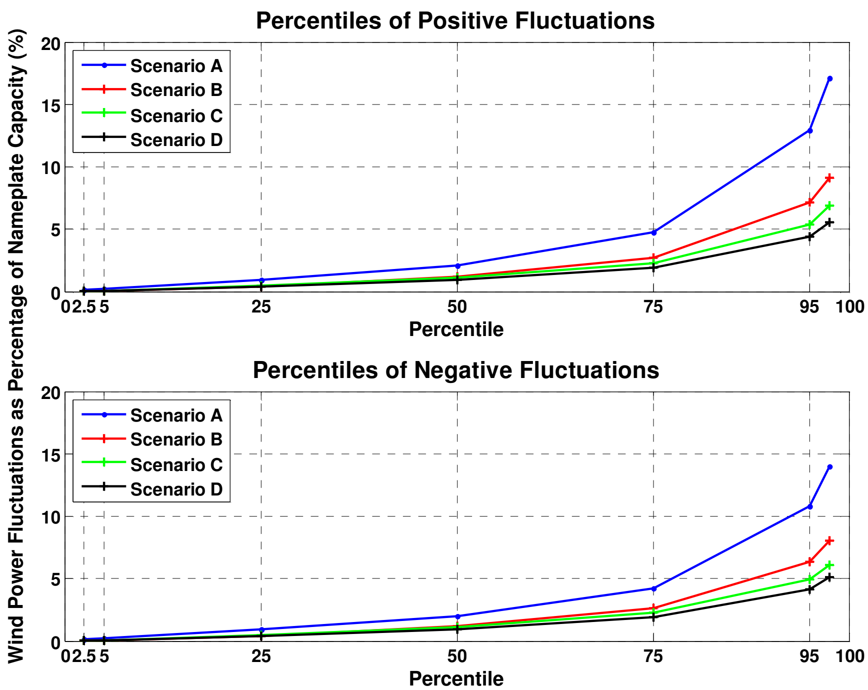

Figure 27: Comparison of the Normalized Percentiles of Simulated Fluctuations for Scenarios A, B, C, and D (10-Minute)

Comparisons of the magnitudes and percentiles of simulated 1-minute fluctuations for the various scenarios are displayed in Figure 28 and Figure 29. Comparisons of the normalized magnitudes and percentiles of simulated 1-minute fluctuations for the various scenarios are displayed in Figure 30 and Figure 31. Complete statistics for the normalized magnitudes of 1-minute fluctuations are show in Table 30 through Table 32 of Appendix 1.

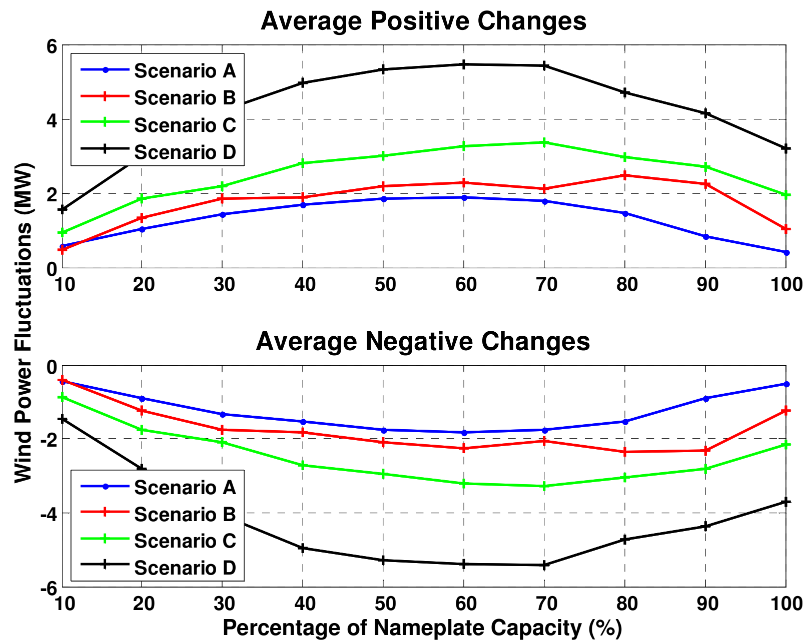

Figure 28: Comparison of the Magnitudes of Simulated Fluctuations for Scenarios A, B, C, and D (1-Minute)

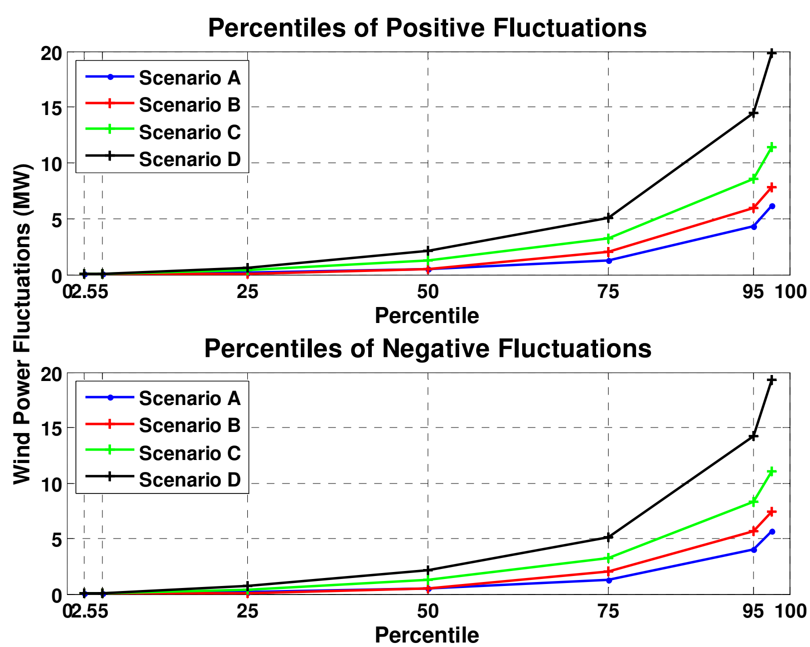

Figure 29: Comparisons of the Percentiles of Simulated Fluctuations for Scenarios A, B, C, and D (1-Minute)

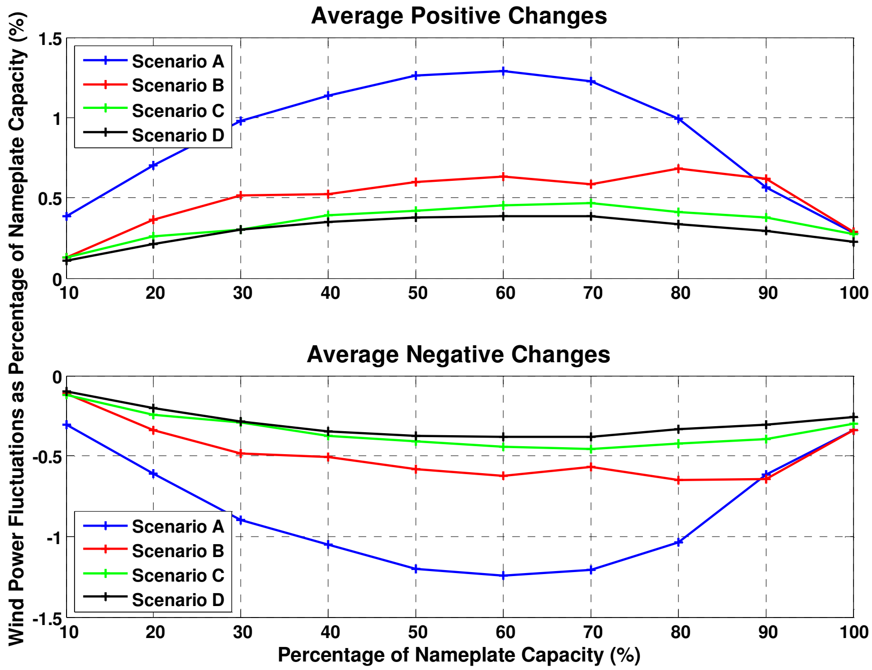

Figure 30: Comparison of the Normalized Magnitudes of Simulated Fluctuations for Scenarios A, B, C, and D (1-Minute)

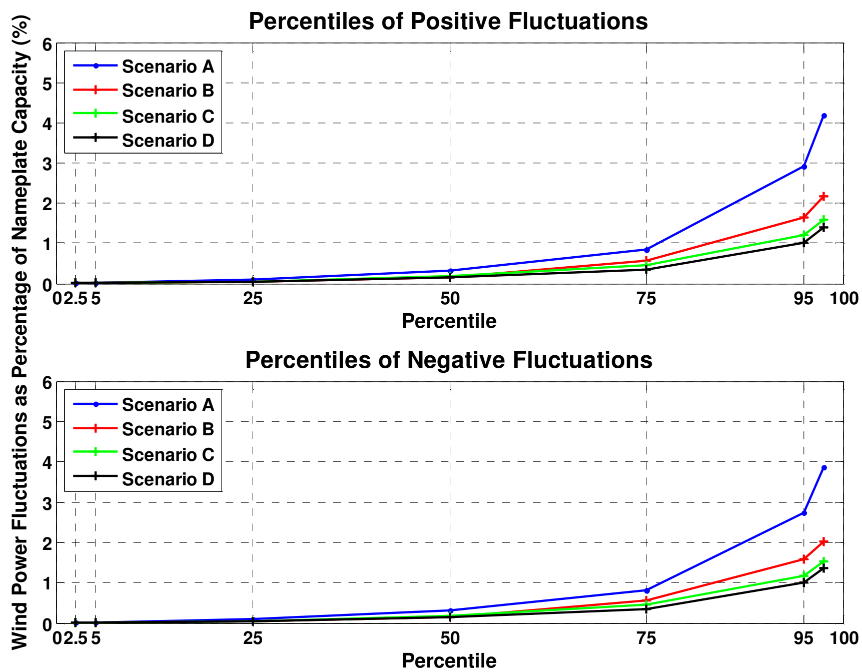

Figure 31: Comparison of the Normalized Percentiles of Simulated Fluctuations for Scenarios A, B, C, and D (1-Minute)

5.2.2 Hypothetical Geospatial Diversity Development Scenarios

The top percentiles of simulated 10-minute and 1-minute fluctuations for the hypothetical geospatial diversity scenarios are summarized in Table 7 and Table 8. These values are independent of the direction (positive and negative) of fluctuation. It can be seen that the magnitude of the simulated wind power fluctuations increase with decreasing regional dispersion. For example, in Table 7, the maximum of the simulated 10-minute fluctuations are 266MW, 335MW, and 481MW (or 18.3%, 23.1%, and 33.2% of capacity) for Scenarios E, F, and G respectively. In Table 8, the maximum of the simulated 1-minute fluctuations are 164MW, 185MW, and 284MW (or 11.3%, 12.8%, and 19.6% of capacity) for Scenarios E, F, and G respectively. Comparisons of the magnitudes and percentiles of simulated 10-minute fluctuations for the various scenarios are displayed in Figure 32 and Figure 33. Complete statistics for the normalized magnitudes of 10-minute fluctuations are shown in Table 33 through Table 35 of Appendix 1. The frequency distributions of power for 10-minute time series are shown in Table 39 through Table 42 of Appendix 1.

Table 7: Percentiles of Simulated 10-Minute Fluctuations for Scenarios E, F, and G (MW)

	95.0%	97.5%	99.5%	Maximum
Scenario E 1450 MW most dispersed	62.21	77.14	118.58	265.60
Scenario F 1450 MW	72.51	92.58	152.07	335.01
Scenario G 1450 MW most concentrated	81.92	105.57	181.66	481.02

Table 8: Percentiles of Simulated 1-Minute Fluctuations for Scenarios E, F, and G (MW)

	95.0%	97.5%	99.5%	Maximum
Scenario E 1450 MW most dispersed	16.08	21.75	37.78	163.83
Scenario F 1450 MW	18.16	25.01	45.38	185.14
Scenario G 1450 MW most concentrated	20.17	28.45	54.05	284.16

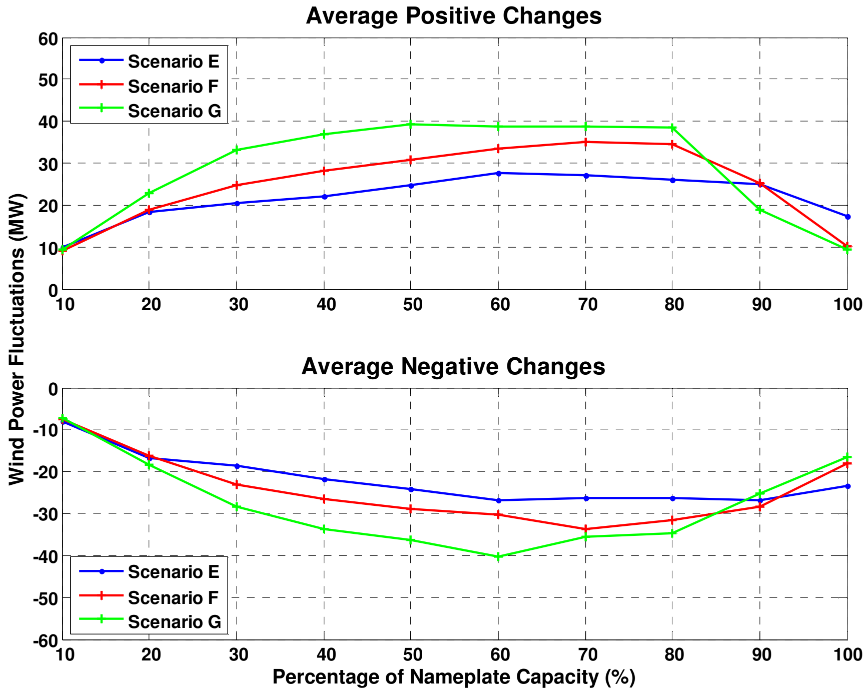

Figure 32: Comparison of the Magnitudes of Simulated Fluctuations for Scenarios E, F, and G (10-Minute)

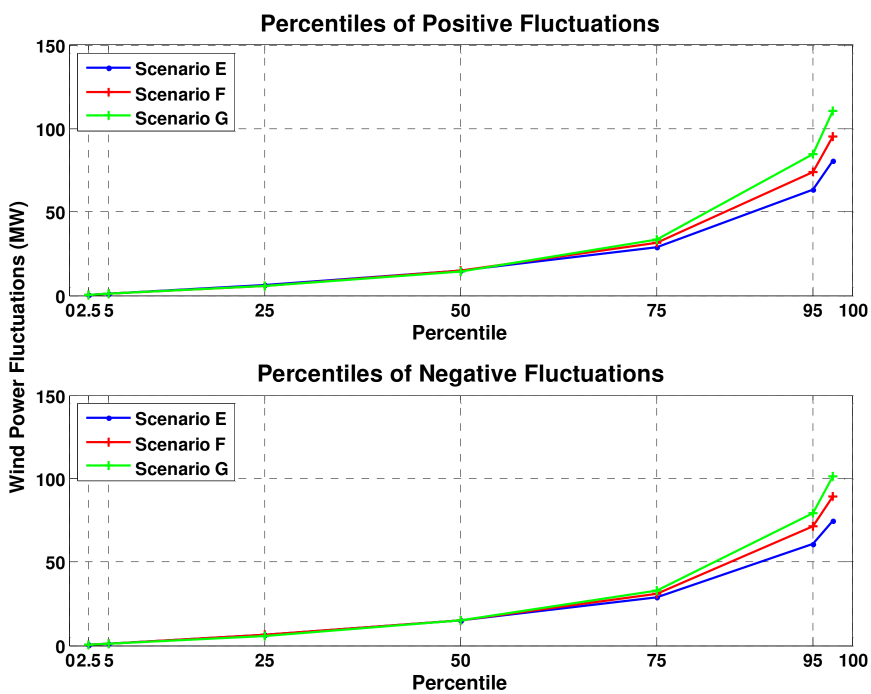

Figure 33: Comparison of the Percentiles of Simulated Fluctuations for Scenarios E, F, and G (10-Minute)

Comparisons of the magnitudes and percentiles of simulated 1-minute fluctuations for the various scenarios are displayed in Figure 34 and Figure 35. Complete statistics for the normalized magnitudes of 1-minute fluctuations are in Table 36 through Table 38 of Appendix 1.

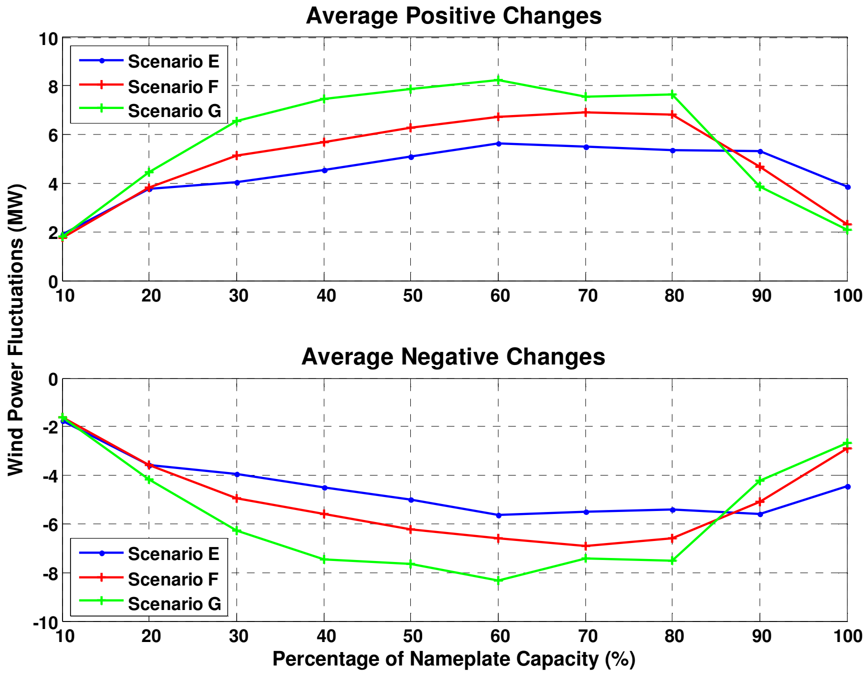

Figure 34: Comparison of the Magnitudes of Simulated Fluctuations for Scenarios E, F, and G (1-Minute)

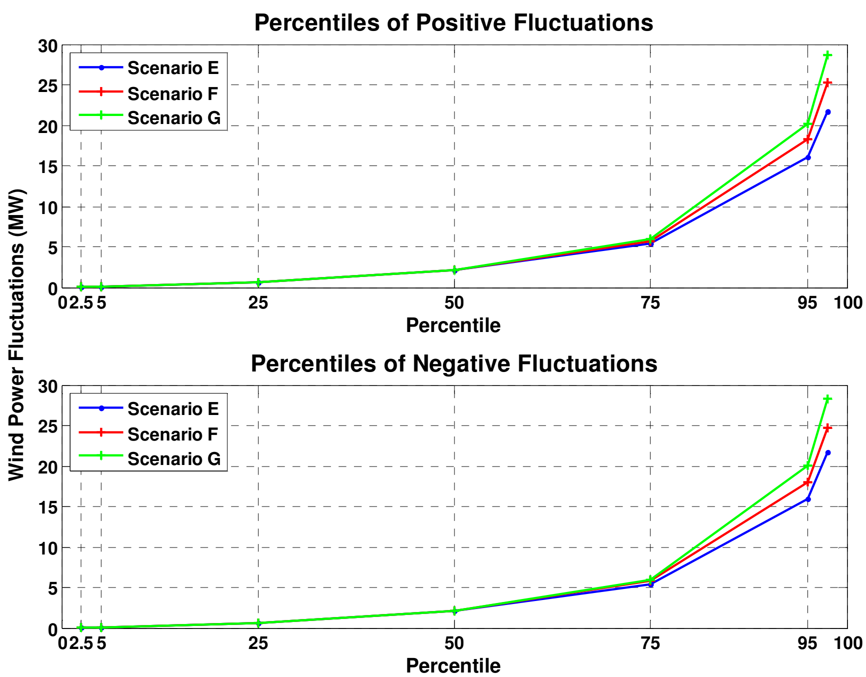

Figure 35: Comparisons of the Percentiles of Simulated Fluctuations for Scenarios R, F, and G (1-Minute)

6 Wind Power Variability Conclusions

One of the objectives of this study was to simulate wind power generation based on proposed development scenarios in which the wind power capacity ranges from 144 MW to 1450 MW. Additional hypothetical scenarios based on varying degrees of regional diversity were studied. Based on the investigation of fluctuation characteristics of the existing WPFs in Montana, a modified multi-turbine power curve approach was proposed. The approach was validated in previous studies by comparing the measured and simulated fluctuations within a WPF and a region.

The study then assessed the magnitude and frequency of wind power fluctuations at different wind energy penetration levels. The major statistical findings can be summarized as follows:

- The magnitude of power fluctuations caused by wind speed variations for the existing WPFs was stochastic in nature. Half of the 10-minute fluctuations did not exceed 1.3% of the capacity while half the 1-minute fluctuations did not exceed 0.2%. Also, the fluctuations were seldom extreme. For example, the 97.5 percentile of 10-minute measured fluctuation among the 2 existing WPFs was 14.4% of the corresponding installed capacity while it was 3.6% for 1-minute fluctuations.

- Three growth scenarios based on proposed developments were studied to assess the impact of increasing state-wide capacity on the state-wide fluctuations. The absolute magnitude of fluctuations increased when the system nameplate capacity increased. For example, the 97.5 percentiles of 10-minute simulated fluctuations for Scenarios A, B, C, and D were 20.7, 30.2, 46.8 and 73.9 MW respectively, while they were 5.2, 7.6, 11.3, and 19.6 MW for 1-minute simulated fluctuations. The normalized fluctuations, however, decreased when the system nameplate capacity increased. The normalized 97.5 percentiles of 10-minute simulated fluctuations for Scenarios A, B, C, and D were 14.4%, 8.4%, 6.3%, and 5.1% of the corresponding total capacity while they were 3.6%, 2.1%, 1.5%, and 1.4% for 1-minute simulated fluctuations.

- To demonstrate the effect of geographical dispersion on power fluctuations, three scenarios were studied; each with the same state-wide capacity but varying regional distribution. The results show that there is a lesser degree of variability when wind power is evenly distributed across four regions as compared to when wind power is concentrated in 2 regions or 1 region. For example, the 97.5 percentiles of 10-minute simulated fluctuations for Scenarios E, F, and G were 77.1, 92.6, and 105.6 MW, respectively, while they were 21.8, 25.0, and 28.5 MW for 1-minute simulated fluctuations.

7 Electric System Impact Modeling Methodologies and Analysis Steps

Having simulated several wind power development scenarios for the state of Montana, the impact of these scenarios on the NWE interconnected electrical system were assessed. Two methodologies were used to assess system impact: standard statistical methods and the modified AESO time simulation. Statistical methods examined the variability associated with simulated wind power and historical load data. The time simulation method used ramp-rate limited generator behavior modeling of the energy and ancillary markets, simulated wind power data, actual load data, actual interchange data, and load forecast data all synchronized for the study period.

7.1 Statistical Assessment of Electrical System Impact

The statistical analysis was an evaluation of the magnitude of wind power variability compared to the combined system variability. The combined system variability was defined as the variability associated with the system load plus interchange schedule less the simulated wind power. An assessment of the combined system variability could indicate the impact on regulating reserves.

7.1.1 Methodologies

The variability analysis was conducted for three distinct time frames. Magnitude of variability was probabilistic in nature and all values were reported at the 97.5 percentile; meaning 97.5% of the time the magnitude of variability was at or below the listed values. Data with a time resolution of 1-minute was used for this statistical analysis. Table 9 summarizes the methods used to assess combined system variability.

Table 9: Description of Statistical Methods for Assessing Combined System Variability

Method	**Time Frame**		**Description of Method**
	Resolution	**Interval**	
1-minute fluctuation	1-minute	2 minutes	97.5 percentile of all differences between two adjacent minutes
Intra 60-minute fluctuations	60-minute average of 1-minute data	60 minutes	97.5 percentile of all maximum step changes within a 60-minute period
Inter 60-minute fluctuations	60-minute average of 1-minute data	120 minutes	97.5 percentile of all differences between two adjacent 60-minute averages

7.2 Time Simulation Methods, Assumptions, and Validation

The time simulation model produced the supply and demand deviations with a 1-minute resolution to calculate system performance measures. The system performance measure studied was the North American Electric Reliability (NERC) Control Performance Standard 2 (CPS2).

It was recognized in the development of the time simulation model that many aspects of system operations were not modeled; this includes system frequency deviations, generator contingencies or volatility (in both the energy and ancillary market), and normal changes in the deployment strategy of regulating reserves. As a result of these modeling limitations, there are marginal discrepancies between the modeled system performance and the actual system performance. Assessing the incremental effect of the different wind power scenarios, however, would be reasonable since the only parameter that changes between scenario analyses is wind power penetration.

7.2.1 Methodologies

The model simulated energy market dispatches and the minute-by-minute electrical system response. NWE dispatches energy market instructions every 60 minutes; which is the typical interval for Western Electricity Coordinating Council (WECC) members. The model presupposed that the simulated net demand on dispatchable generation was the system load plus scheduled interchange less simulated wind power; which should be satisfied by the energy market. The simulation logic is summarized in Figure 36 below[9].

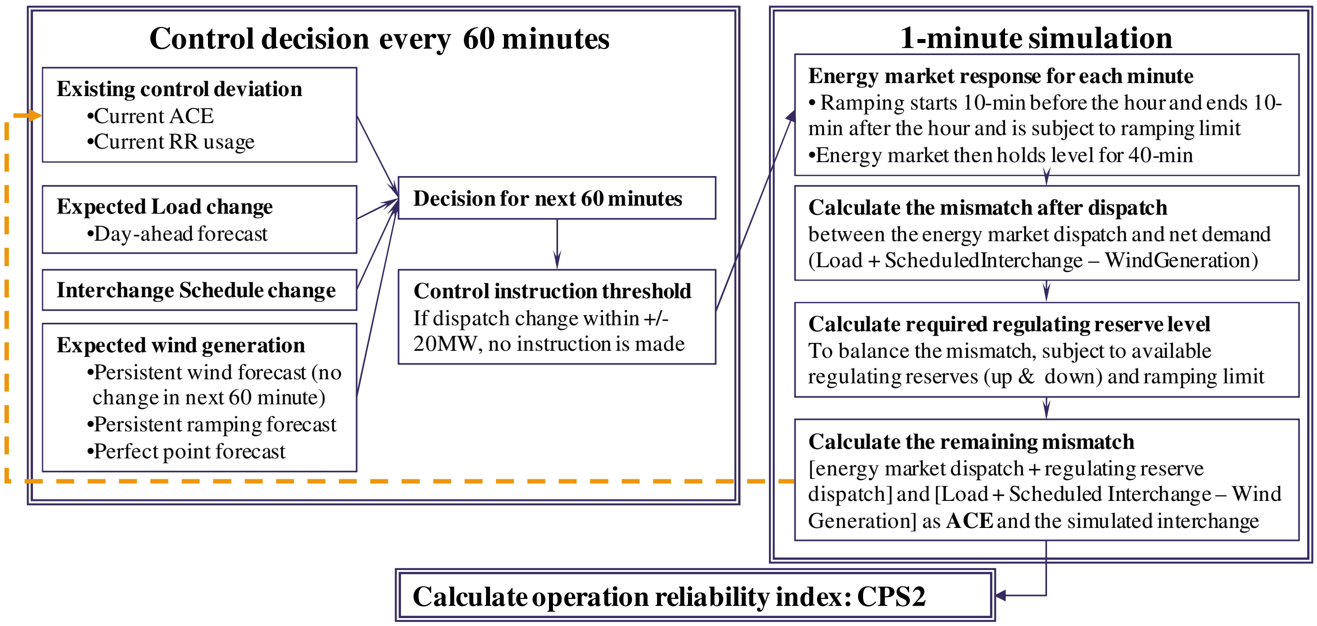

Figure 36: Logic for System Dispatch Time Simulation

Definition of terms:

- ACE – Area Control Error, the instantaneous discrepancy between supply and net demand; which can be equally quantified as the difference between actual interchange and scheduled interchange.

- RR – Regulating Reserve, a range limited ancillary service that automatically responds to system discrepancies to minimize ACE within a dispatch interval.

- CPS2 – Control Performance Standard 2, a performance rating established by NERC that limits the ACE for each system operator. NERC requires that 90% of the clock-ten-minute averages of ACE for a calendar month must be below a certain threshold (known as the L10). The current L10 value assigned to NWE by NERC is 23.99MW. The CPS2 rating, then, is the monthly percentage of ten-minute averages of ACE that are less than L10.

Wind forecasting was recognized as a viable mitigating measure for the wind variability. The simulator incorporated and explored three wind power forecasting methods for each wind power development scenario. The simulated CPS2 ratings were obtained for all iterations; which provided the basis for

[9] During actual operation, the system operator is not able to make changes for the next hour, but can for the make changes for the hour after.

comparing system reliability. For these simulations, the regulating reserve range was maintained at the current level. The three forecasting methods were:

1. *Persistent Forecasting*: In this method it was assumed the wind power at the time of the control decision dispatch will remain the same for the next 60-minute interval. This is the most basic forecast capability since wind power does not contribute to the net expected change in demand on conventional generation.

2. *Persistent Ramp Forecasting*: In this method, it was assumed that at the time of a control decision dispatch the change in wind power over the next 60-minute interval would equal the change in the next 60-minute interval. The forecasted changes in wind were limited so that forecasted wind power levels were always positive and did not exceed the wind power capacity. In this method, the expected change in the wind power generation would contribute to the expected change in the net demand on the conventional generation and the dispatch decision would adjust accordingly.

3. *Perfect Hourly Forecasting*: Commercial forecasting software or services would provide a predicted average wind power over a certain time period. For each simulated dispatch, this can be replicated by calculating the wind power average for the next 60 minutes directly from the simulated wind power time series. In the method then, the expected change in wind power will be the average wind power of the next 60 minutes minus the average wind power of the previous 60 minutes. This would contribute to the expected change in the net demand on the conventional generation and the dispatch decision would adjust accordingly.

Increasing regulating reserves could also address wind variability. To evaluate the merits of this mitigating method, for each wind development scenario, the regulating reserve range required to maintain CPS2 compliance was determined. The required regulating reserve range increase was presented as a factor of the current regulating reserve range. For these simulations, the wind forecasting method was maintained as persistent forecasting.

7.2.2 Model Assumptions

A key assumption used in the time simulation model is the ramp rate limited behavior of the generators that participate in the energy and ancillary markets. The assumptions used to characterize the behavior of these generators were modeled then compared to actual behavior. Validation of this assumption is provided in the following section; Figure 37 shows a comparison of simulated response of the generators versus actual behavior of the generators.

Assumptions in the time simulation model include:

- The energy market ramp rate was limited to 35MW/min for off-peak hours (23:00 to 08:00) and 5MW/min for on-peak hours (08:00 to 23:00);

- The regulating reserve ramp rate was limited at 10% of the regulating range per minute. The typical ramp rates may be greater than this value, but it was used for the purpose of simulation;

- Energy market ramps begin 10 minutes before the hour and end 10 minutes after the hour and ramp in a linear fashion;

- The regulation reserve set point was targeted to be in the middle of its range[10]; and

- Any periods during which system and/or wind power data quality was questionable were excluded from the analysis.

The time simulation does not:

- Consider transmission capability or development;

- Consider system variability as a result of contingencies internal or external to the NWE electrical system;

- Examine variability of dispatchable generators; or

- Examine variability of individual wind facilities.

7.2.3 Model Validation

The system dispatch time simulation model uses historical data to represent system operating conditions. The actual historical data for internal system loads, interchange schedules, regulation reserve range, and simulated wind power (all at 1-minute intervals) were all synchronized. To ensure reasonable accuracy of the model, a simulation using only the existing wind development (Scenario A) was compared to the historical system response. Figure 37 shows, that for a sample time period, the simulated response of the generators compares well to the actual behavior of the generators. Similarly, Figure 38 shows that for the same sample time period, the simulated ACE compares well to the actual ACE. Finally, Figure 39 shows the simulated and actual CPS2 rating for the 12-month study period compare well. The model captured the general trend of the actual CPS2 rating and any discrepancies can likely be attributed to the modeling limitations discussed.

[10] This is a goal for operation, but not always achievable. This may result in a CPS2 performance lower than modeled.

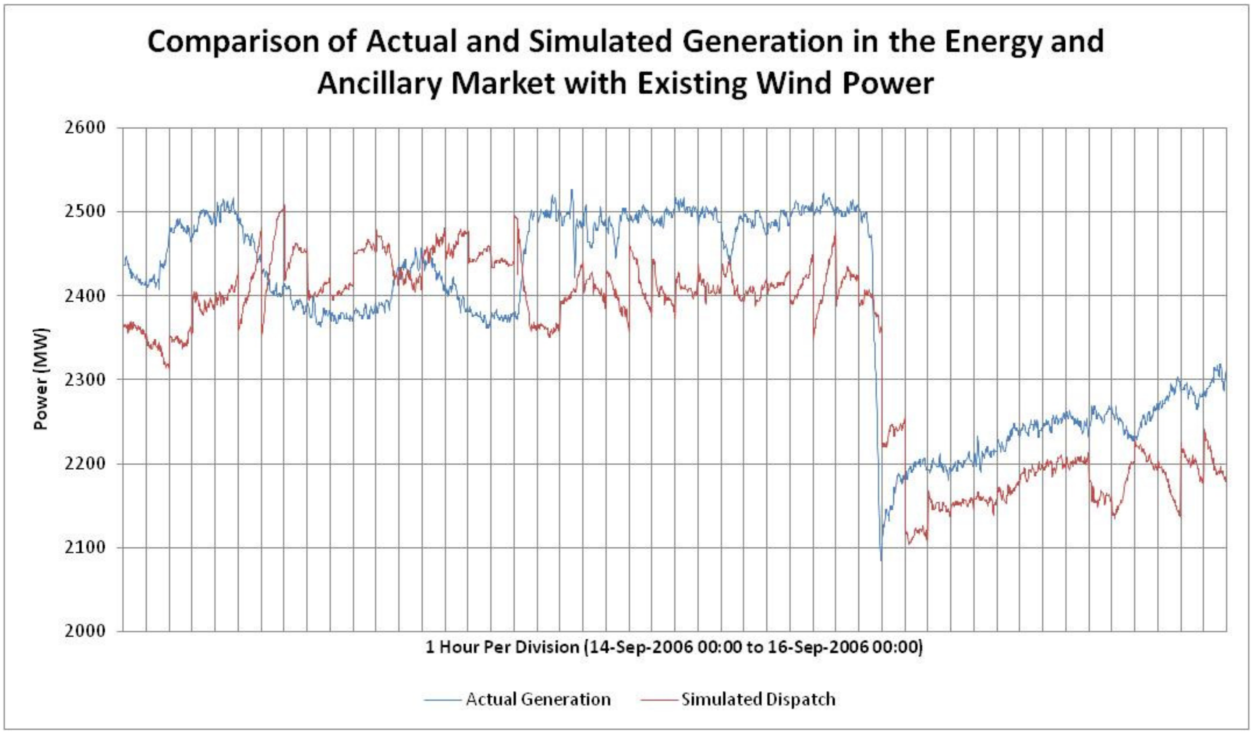

Figure 37: Validation of Ramp-Rate Limited Energy and Ancillary Market Generators

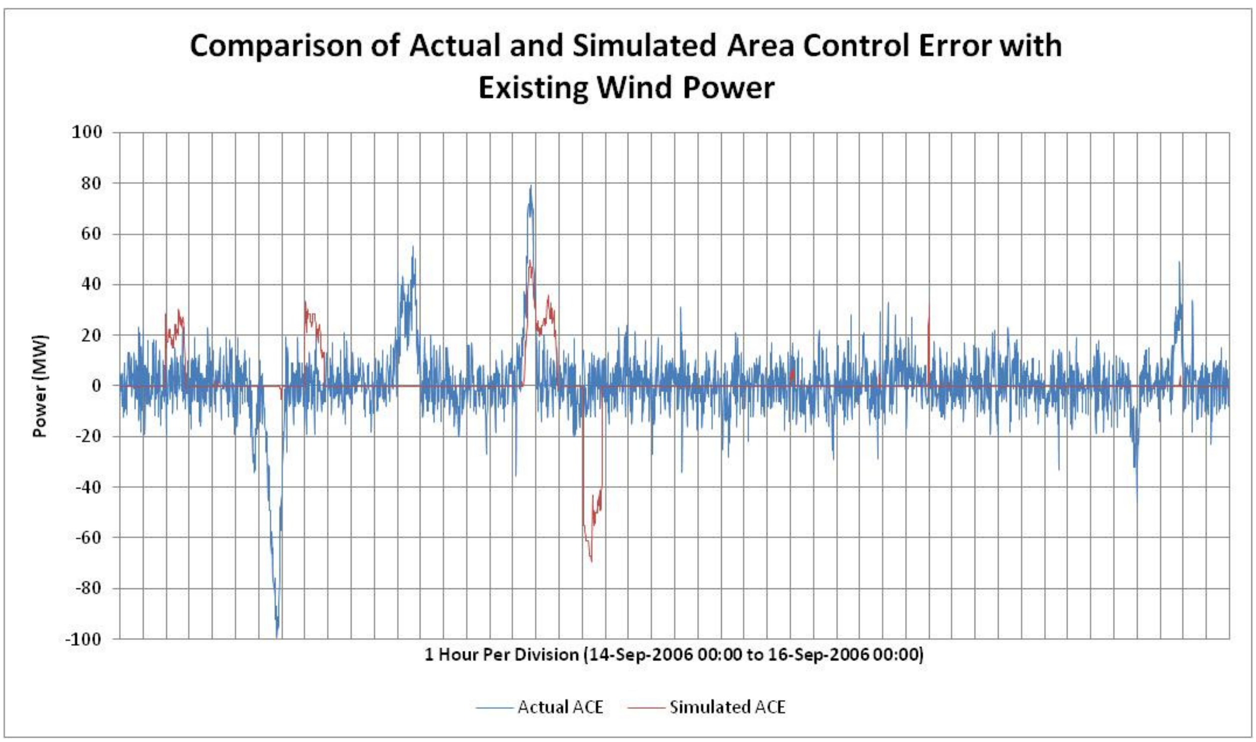

Figure 38: Comparison of Simulated and Actual Area Control Error

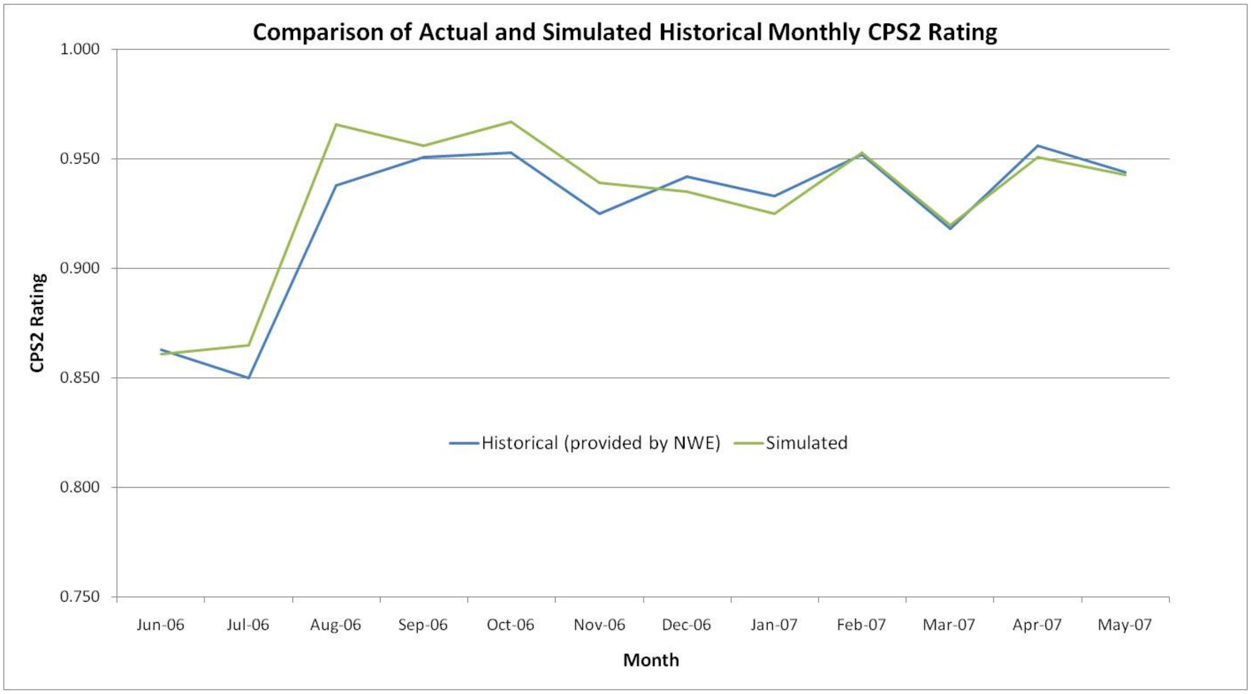

Figure 39: Comparison of Simulated and Actual Historical CPS2 Performance Ratings

8 Electric System Impact Results

8.1 Magnitude of Variability Analysis

Analysis was conducted on 1-minute, intra 60-minute, and inter 60-minute variability for both wind power and the net demand. The results of the analysis for Scenarios A through D was summarized in Table 10 below while analysis for Scenarios E through G was summarized Table 11. Table 46 and Table 47 of Appendix B detail the complete results of the analysis.

Table 10: Summary of Magnitude of Variability for Scenarios A, B, C, and D

1-Minute Summary	Intra 60-Minute Summary	Inter 60-Minute Summary
The 97.5 percentile of 1-minute wind power fluctuations increases from +/-6MW to +20/-19MW when the wind power development level increases from scenario A to D. However, the variability increases at a slower rate than the penetration level increases. The 97.5 percentile of 1-minute net demand fluctuations increases from +11/-10MW to +25/-24MW when the wind power development level increases from scenario A to D. This implies that the 1-minute net demand fluctuations are influenced by the wind power variability.	The 97.5 percentile of intra 60-minute maximum step changes of wind power increases from +14/-13MW to +61/-58MW when the wind power development level increases from scenario A to D. However, the variability increases at a slower rate than the penetration level increases. The 97.5 percentile of intra 60-minute maximum step changes of net demand changes from +201/-240MW to +202/-222MW when the wind power development level increases from scenario A to D. This implies that the intra 60-minute variability is dominated by the existing system variability such as load and scheduled interchange.	The 97.5 percentile of inter 60-minute wind power fluctuations increases from +65/-54MW to +224/-211MW when the wind power development level increases from scenario A to D. However, the variability increases at a slower rate than the penetration level increases. The 97.5 percentile of inter 60-minute net demand fluctuations increases from +189/-214MW to +273/-281MW when the wind power development level increases from scenario A to D. This implies that the inter 60-minute net demand fluctuations are influenced by the wind power variability.

Table 11: Summary of Magnitude of Variability for Scenarios E, F, and G

1-Minute Summary	Intra 60-Minute Summary	Inter 60-Minute Summary
The 97.5 percentile of 1-minute wind power fluctuations increases from +/-22MW to +29/-28MW when the wind power regional concentration increases from scenario E to G. The 97.5 percentile of 1-minute net demand fluctuations increases from +27/-26MW to +34/-33MW when the wind power regional concentration increases from scenario E to G. This implies that the 1-minute net demand fluctuations are influenced by the wind power variability.	The 97.5 percentile of intra 60-minute maximum step changes of wind power increases from +65/-60MW to +96/-88MW when the wind power regional concentration increases from scenario E to G. The 97.5 percentile of intra 60-minute maximum step changes of net demand changes from +208/-221MW to +210/-227MW when the wind power regional concentration increases from scenario E to G. This implies that the intra 60-minute variability is dominated by the existing system variability such as load and scheduled interchange.	The 97.5 percentile of inter 60-minute wind power fluctuations increases from +/-216MW to +289/-296MW when the wind power regional concentration increases from scenario E to G. The 97.5 percentile of inter 60-minute net demand fluctuations increases from +277/-269MW to +322/-344MW when the wind power regional concentration increases from scenario E to G. This implies that the 1-minute net demand fluctuations are influenced by the wind power variability.

8.2 Time Simulation Analysis

For the purpose of comparing system performance for the various wind development scenarios and various wind forecasting methods, a benchmark scenario was first established. The benchmark scenario used the historical wind power (Scenarios A) with persistent forecasting and the current regulating reserve capacity. This was different from the simulated historical scenario because the current regulation capacity was greater than the capacity during the study period (June 2006 to May 2007). Figure 40 shows a comparison of the actual historical, simulated historical, and benchmark CPS2 ratings for the 12 month study period.

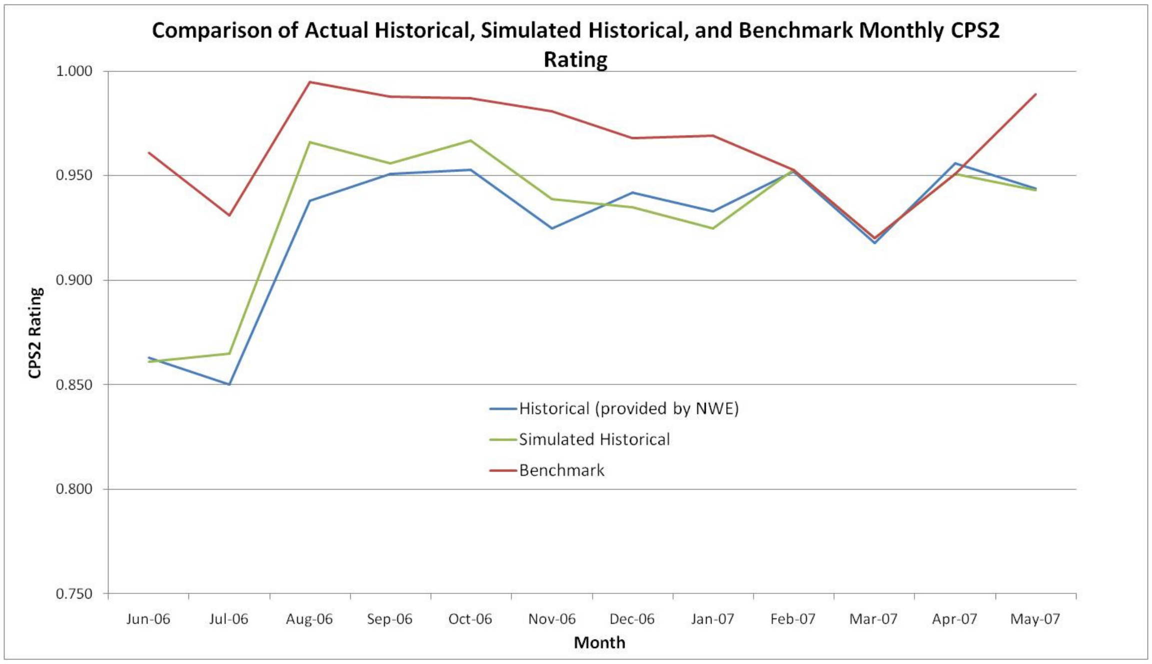

Figure 40: Comparison of Actual Historical, Simulated Historical, and Benchmark CPS2 Performance Ratings

8.2.1 Effect of Wind Forecasting on System Performance

A time simulation was performed for each wind development scenario and each wind forecasting method with the current regulating reserve capacity. Monthly CPS2 ratings were obtained for each iteration to assess their impact on system performance. Using the simplest forecasting method (persistent forecasting), it was found that CPS2 ratings decrease with increased wind power development from the Benchmark Scenario through Scenario B to D as shown in Figure 41. Similarly, the CPS2 ratings decreased with increased wind power regional concentration from Scenario E to G as shown in Figure 42. The effect of wind power forecasting on system performance was determined. For all wind power development scenarios, perfect forecasting resulted in highest CPS2 ratings; next highest was persistent forecasting; and the persistent ramp forecasting resulted in the lowest CPS2 ratings. As an example, the effect of forecasting for development Scenario G is shown in Figure 43. Referring to Figure 44, it was demonstrated that with simulated perfect forecasting, the CPS2 ratings for development Scenarios B through D approached and even exceed the CPS2 rating for the benchmark scenario. Table 48 of Appendix B gives the complete CPS2 results of the system dispatch time simulation for each wind development scenario and each wind forecasting method.

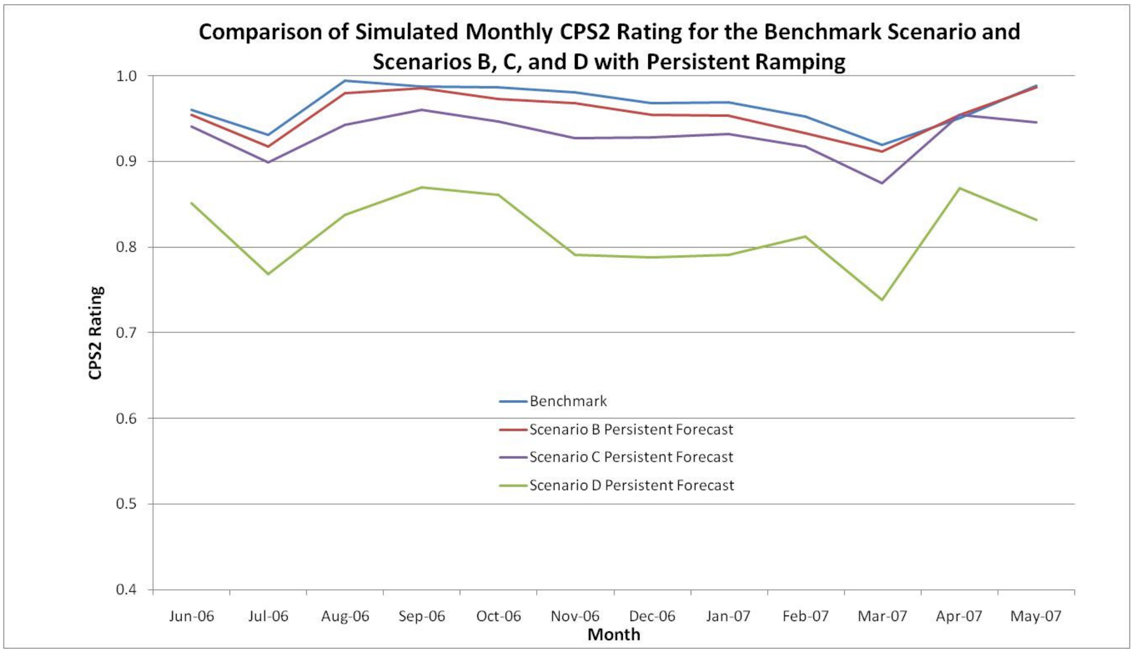

Figure 41: Comparison of Simulated Monthly CPS2 Ratings for the Benchmark Scenario and Scenarios B, C, and D with Persistent Ramping

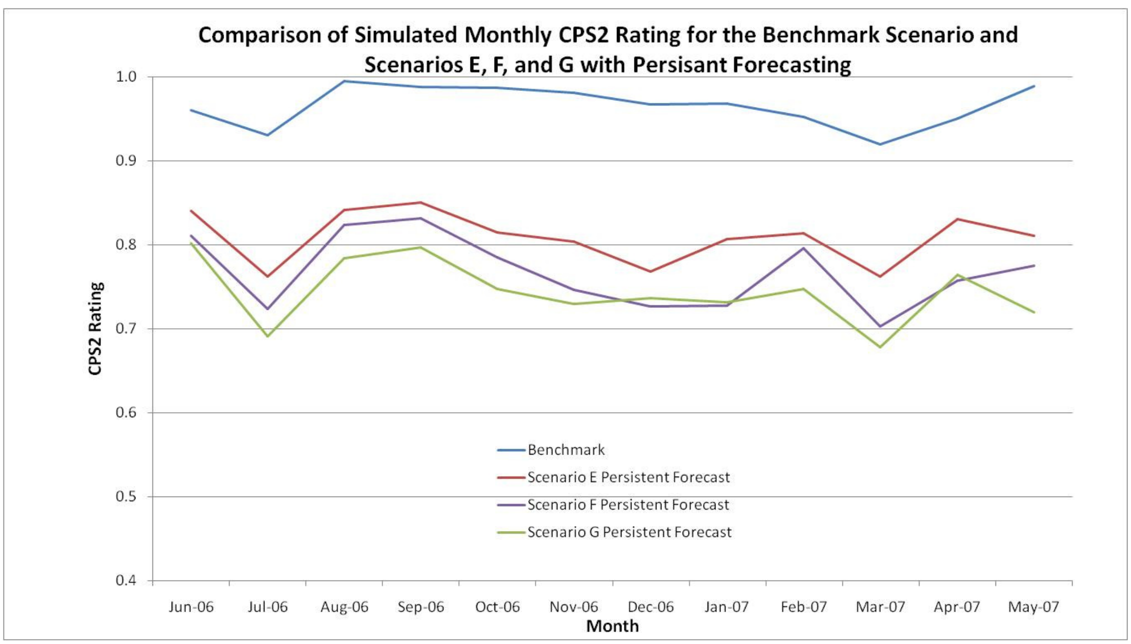

Figure 42: Comparison of Simulated Monthly CPS2 Ratings for the Benchmark Scenario and Scenarios E, F, and G with Persistent Ramping

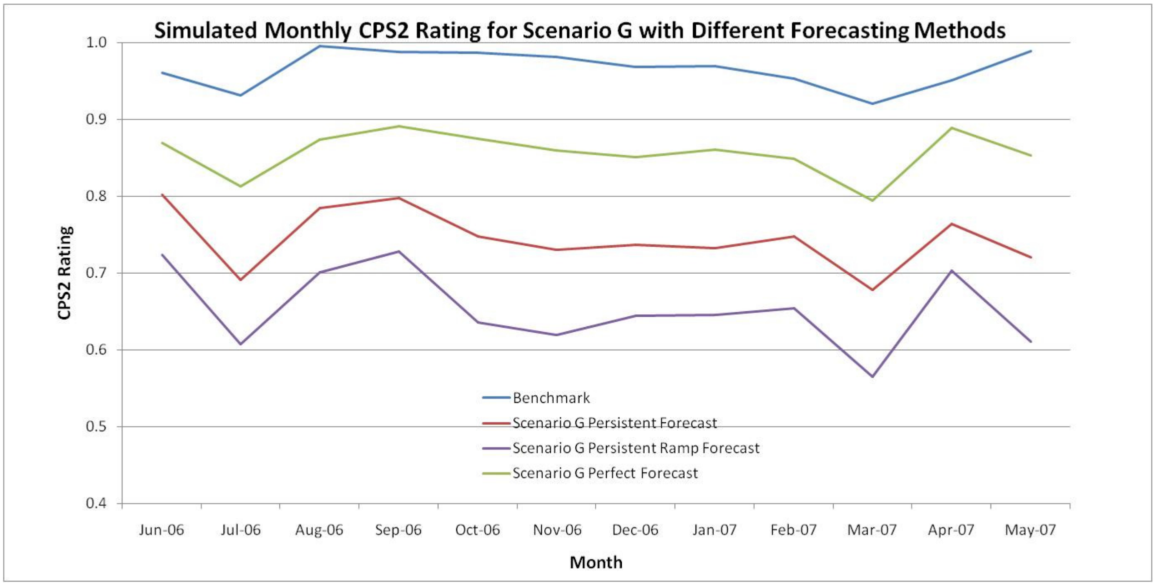

Figure 43: Comparison of Simulated Monthly CPS2 Rating for the Benchmark Scenario and Scenario G with Different Forecasting Methods

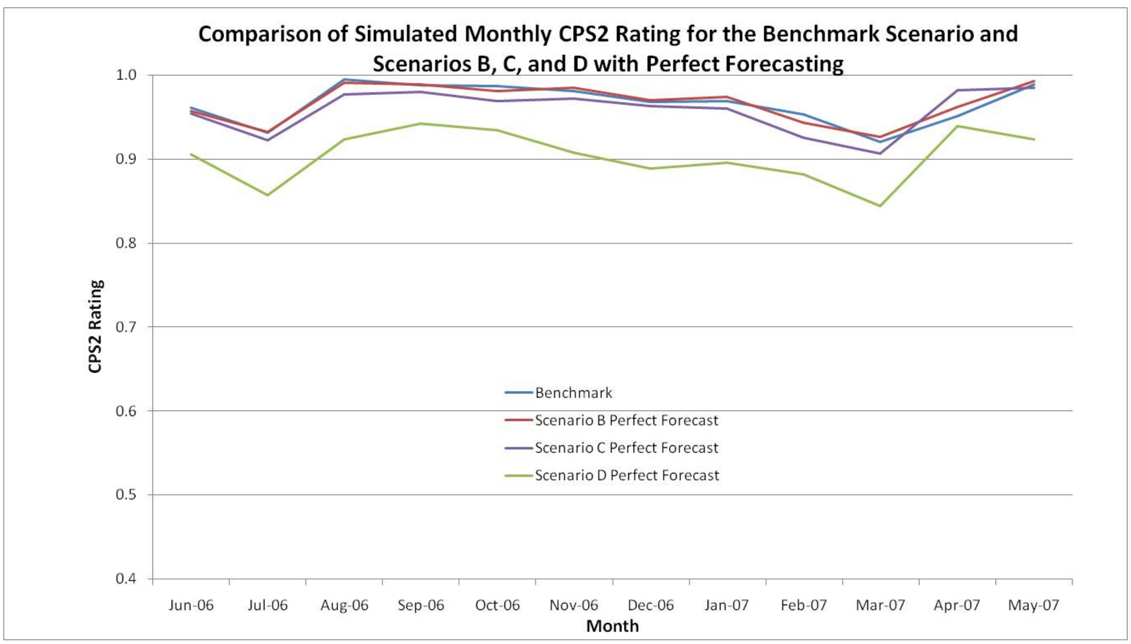

Figure 44: Comparison of Simulated Monthly CPS2 Ratings for the Benchmark Scenario and Scenarios B, C, and D with Perfect Forecasting

8.2.2 Effect of Regulating Reserve on System Performance

Using the persistent forecasting method, the increase in regulating reserve range required to maintain CPS2 compliance for each wind development scenario was determined. To do so, the regulating range was increased from the current available range of 85MW so that the lowest monthly CPS2 rating for a given wind development scenarios was exactly 90%. This represented minimum CPS2 compliance for all twelve months. However, this is not an appropriate choice for determining needed regulation reserve since it does not allow for any margin to cover conditions that vary from those modeled. Without a margin, there is significant risk that during actual operation CPS2 criteria may be violated. It was found that with persistent forecasting, Scenario A and B did not require an increase in regulating range, that is, all twelve months were in CPS2 compliance with the current regulating range. For the two remaining proposed growth development scenarios (Scenarios C and D), additional regulating range was required to maintain CPS2 compliance and the required regulating range increased with increasing wind capacity. For the three hypothetical regional dispersion scenarios (Scenario E, F, and G), it was found that the regulating range required to maintain CPS2 compliance increased with increasing regional concentration of wind power. A more conservative assessment was performed where the CPS2 ratings were required to be at least 91%. Finally, since CPS2 ratings were on average approximately 94% from August 2006 to March 2008, an assessment was performed to determine the requirements to meet this level of performance. Table 12 and Table 13 summarize the additional regulating range required to maintain at least 90%, 91%, and 94% CPS2 ratings for all wind development scenarios.

Table 12: Summary of Increase from Current Value of Regulating Reserve Range (RRR) Required for 90%, 91%, and 94% CPS2 Ratings shown as factor of current levels

Wind Scenario*	Factor of Current Wind Capacity	Factor of current RRR for CPS2 of at least 90% for all months	Factor of current RRR for CPS2 of at least 91% for all months	Factor of current RRR for CPS2 of at least 94% for all months
A	1.00	1.00	1.00	1.44
B	2.49	1.00	1.00	1.68
C	5.15	1.36	1.56	2.15
D	10.07	2.74	3.02	4.32
E	10.07	2.54	2.73	4.05
F	10.07	3.37	3.68	4.67
G	10.07	3.84	4.12	5.44

* For this analysis, wind scenarios were modeled with persistent forecasting method

Table 13: Summary of Increase from Current Value of Regulating Reserve Range (RRR) Required for 90%, 91%, and 94% CPS2 Ratings shown as absolute values

Wind Scenario*	Wind Capacity (MW)	Required RRR for CPS2 of at least 90% for all months (MW)	Required RRR for CPS2 of at least 91% for all months (MW)	Required RRR for CPS2 of at least 94% for all months (MW)
A	144	85	85	122
B	358.5	85	85	143
C	741	116	133	183
D	1450	233	257	367
E	1450	216	232	344
F	1450	286	313	397
G	1450	326	350	462

* For this analysis, wind scenarios were modeled with persistent forecasting method

The regulating reserve requirements to maintain a minimum CPS2 rating of 94% offered insight to the requirements of maintaining status-quo system performance. It was determined that a factor of 1.44 and 1.68

of the current regulating reserves would meet this requirement for wind Scenario A and Scenario B respectively. This corresponds to a regulating range of 122.4MW and 142.8MW for Scenario A and B respectively. Therefore, to reach the same system performance as Scenario A, the required increment in regulating range from Scenario A to B is approximately 20MW. To further validate the incremental requirements, it was determined that the CPS2 ratings for Scenario B with 20MW more than the current regulating range approached and exceeded the CPS2 ratings of Scenario A with just the current regulating range. The reader must use caution if these results are applied to determine regulation required for incremental wind resource additions. For the analysis to apply, the added resources must result in geographic diversity of the resources that reflects the geographic diversity in this study. The results of this comparison are shown in Table 14 and Figure 45.

Table 14: System Dispatch Time Simulation CPS2 Ratings for all Benchmark Scenario and Scenario B with 105MW Regulating Reserve Range

Scenario	RRR+ (MW)	Wind Forecast Method	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07
A	85	Persistent*	0.961	0.931	0.995	0.988	0.987	0.981	0.968	0.969	0.953	0.920	0.951	0.989
B	105	Persistent	0.966	0.929	0.987	0.99	0.98	0.976	0.966	0.961	0.937	0.926	0.962	0.989

*Scenario A with Persistent Forecasting is referred to as the benchmark scenario
+RRR: abbreviation for Regulating Reserve Range

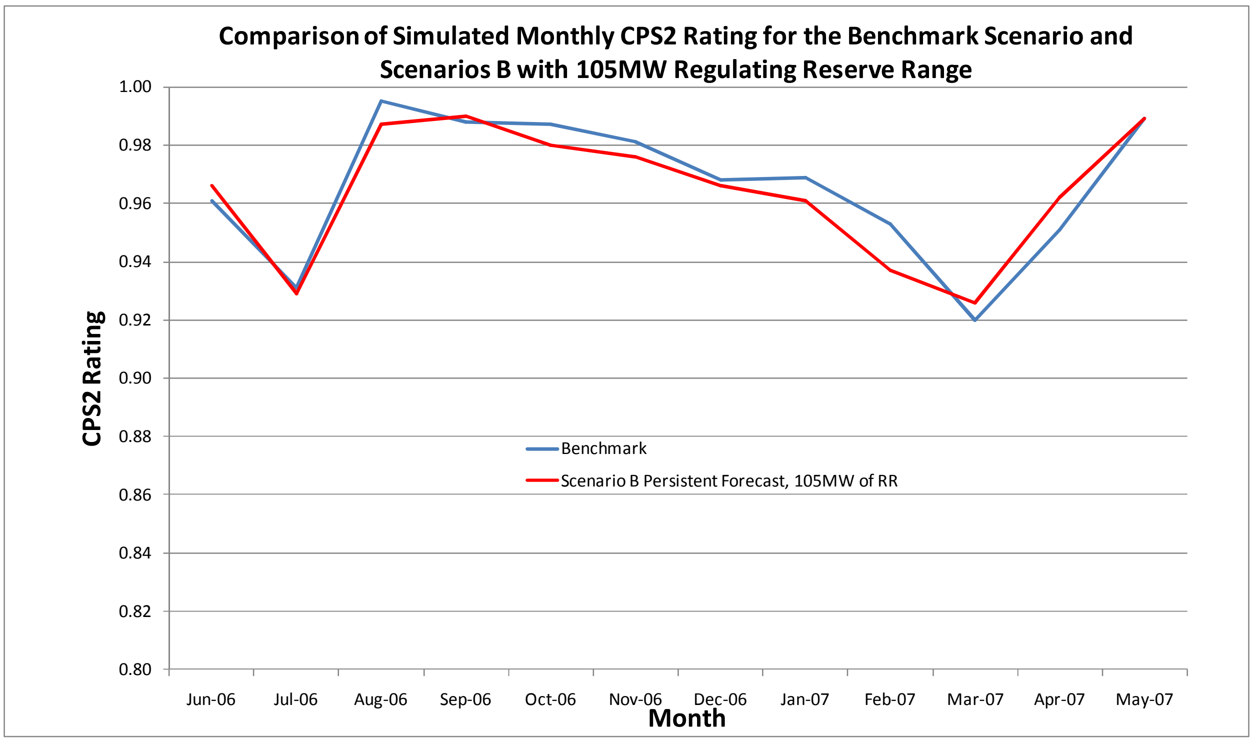

Figure 45: Comparison of Simulated Monthly CPS2 Rating for the Benchmark Scenario and Scenario B with 105MW Regulating Reserve Range

9 Electrical System Impact Conclusions

The statistical and system dispatch time simulations for all wind development scenarios provide insight into the effects of wind power on system operation.

9.1 Summary of Statistical Analysis Findings

The statistical analysis provided some notable findings:

- In the 60-minute and less time frame, wind power variability increased with wind power development, but not in proportion to the wind power development. That is, the wind power variability increases at a lower rate than the installed capacity. Also, in the 60-minute and less time frame wind variability increased with increasing regional concentration of wind power;

- The intra 60-minute maximum variability of the net demand is dominated by the existing system variability, namely the changes in load and scheduled interchange.

9.2 Summary of Time Simulation Analysis

The system dispatch time simulation analysis also provided some notable findings:

- System performance determined with the historical wind power development (Scenario A) and historical regulating range produced results similar to the actual system performance for the same time period. This served to validate the model;

- The time simulation for the historical scenario resulted in two CPS2 violations which matched the historical system performance;

- The Benchmark Scenario (historical wind power with current regulating reserve capacity) resulted in no CPS2 violations;

- For the proposed wind power growth scenarios (Scenarios B, C, and D), the time simulations with persistent wind power forecasting showed a decrease in CPS2 ratings with increased wind capacity. Scenario B resulted in no CPS2 violations, Scenario C resulted in two CPS2 violations, while Scenarios D resulted in all twelve months were in CPS2 violation;

- For the hypothetical geospatial diversity scenarios (Scenarios E, F, and G), CPS2 ratings decreased with increased regional concentration of wind power;

- An incremental benefit to CPS2 ratings was seen with perfect forecasting simulations relative to simple persistent forecasting;

- An incremental detriment to CPS2 rating was seen with persistent ramp forecasting relative to simple persistent forecasting;

- For proposed wind power growth Scenarios C and D, the regulating reserve range required to maintain minimum CPS2 compliance increased with increasing wind power capacity; and

- For the hypothetical geospatial diversity scenarios (Scenarios E, F, and G), the additional regulating reserve range required to maintain CPS2 compliance increased with increasing wind power regional concentration

10 References

[1] Per N∅rgard and Hannele Holttinen, A Multi-Turbine Power Curve Approach. Proceedings of Nordic Wind Power. Conference NWPC'04, 1.-2.2004.

[2] Yih-huei Wan and Demy Bucaneg, Jr., 2002. Short-Term Power Fluctuations of Large Wind Power Plants. National Renewable Energy Laboratory.

[3] Per N∅rgard, Hannele Holttinen and Astrid Petterteig. Fluctuations and Predictability of Wind and Hydropower. Ris∅ National Laboratory, Denmark, 2004.

[4] David Baker and Rui Wang. Alberta Wind Power Variability Study. Phoenix Engineering, Canada, 2005.

[5] John Kehler, Ming Hu, and Darren McCrank.. Incremental Impact on System Operations with Increased Wind Power Penetration, Phase 1. Alberta Electric System Operator, Canada, 2005.

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11 Appendix A: Wind Data Quality and Additional Variability Statistics

Table 15: Distribution of Qualified Wind Data in Terms of the Number of WPFs (Scenario B)

Number Of WPFs Providing Valid Measurement	Number Of Valid Records	Percentage of Time (%)
<= 1	0	0
2	65	0.1
3	995	1.9
4	2208	4.2
5	49288	93.8

Table 16: Distribution of Qualified Wind Data in Terms of the Nameplate Capacity (Scenario B)

Capacity (MW)	Number Of Valid Records	Percentage of Time (%)
[0 - 100)	0	0
[100 - 200)	65	0.1
[200 - 300)	2197	4.2
[300 - 400)	50294	95.7

Table 17: Distribution of Qualified Wind Data in Terms of the Number of WPFs (Scenario C)

Number Of WPFs Providing Valid Measurement	Number Of Valid Records	Percentage of Time (%)
<= 3	0	0
4	4	0.0
5	162	0.3
6	668	1.3
7	1178	2.2
8	3585	6.8
9	46959	89.4

Table 18: Distribution of Qualified Wind Data in Terms of the Nameplate Capacity (Scenario C)

Capacity (MW)	Number Of Valid Records	Percentage of Time (%)
[0 - 300)	0	0
[300 - 400)	86	0.2
[400 - 500)	858	1.6
[500 - 600)	1880	3.6
[600 - 700)	1449	2.8
[700 - 800)	48283	91.9

Table 19: Distribution of Qualified Wind Data in Terms of the Number of WPFs (Scenario D)

Number Of WPFs Providing Valid Measurement	Number Of Valid Records	Percentage of Time (%)
<= 4	0	0
5	100	0.2
6	522	1.0
7	117	0.2
8	172	0.3
9	127	0.2
10	359	0.7
11	916	1.7
12	1141	2.2
13	3103	5.9
14	45999	87.5

Table 20: Distribution of Qualified Wind Data in Terms of the Nameplate Capacity (Scenario D)

Capacity (MW)	Number Of Valid Records	Percentage of Time (%)
[0 - 300)	0	0
[300 - 400)	11	0.0
[400 - 500)	491	0.9
[500 - 600)	134	0.3
[600 - 700)	107	0.2
[700 - 800)	59	0.1
[800 - 900)	151	0.3
[900 - 1000)	236	0.4
[1000 - 1100)	455	0.9
[1100 - 1200)	927	1.8
[1200 - 1300)	1526	2.9
[1300 - 1400)	2166	4.1
[1400 - 1500)	46293	88.1

Table 21: Distribution of Qualified Wind Data in Terms of the Number of WPFs (Scenario E)

Number Of WPFs Providing Valid Measurement	Number Of Valid Records	Percentage of Time (%)
<= 1	0	0
2	100	0.2
3	516	1.0
4	179	0.3
5	539	1.0
6	1297	2.5
7	3740	7.1
8	46185	87.9

Table 22: Distribution of Qualified Wind Data in Terms of the Nameplate Capacity (Scenario E)

Capacity (MW)	Number Of Valid Records	Percentage of Time (%)
[0 - 500)	0	0
[500 - 600)	113	0.2
[600 - 700)	28	0.1
[700 - 800)	531	1.0
[800 - 900)	123	0.2
[900 - 1000)	483	0.9
[1000 - 1100)	1400	2.7
[1100 - 1200)	369	0.7
[1200 - 1300)	2190	4.2
[1300 - 1400)	1134	2.2
[1400 - 1500)	46185	87.9

Table 23: Distribution of Qualified Wind Data in Terms of the Number of WPFs (Scenario F)

Number Of WPFs Providing Valid Measurement	Number Of Valid Records	Percentage of Time (%)
<= 1	0	0
2	100	0.2
3	517	1.0
4	175	0.3
5	536	1.0
6	1286	2.4
7	3694	7.0
8	46248	88.0

Table 24: Distribution of Qualified Wind Data in Terms of the Nameplate Capacity (Scenario F)

Capacity (MW)	Number Of Valid Records	Percentage of Time (%)
[0 - 100)	0	0
[100 - 200)	56	0.1
[200 - 300)	0	0.0
[300 - 400)	12	0.0
[400 - 500)	483	0.9
[500 - 600)	21	0.0
[600 - 700)	152	0.3
[700 - 800)	137	0.3
[800 - 900)	235	0.4
[900 - 1000)	263	0.5
[1000 - 1100)	632	1.2
[1100 - 1200)	1454	2.8
[1200 - 1300)	1146	2.2

Capacity (MW)	Number Of Valid Records	Percentage of Time (%)
[1300 - 1400)	1406	2.7
[1400 - 1500)	46559	88.6

Table 25: Distribution of Qualified Wind Data in Terms of the Number of WPFs (Scenario G)

Number Of WPFs Providing Valid Measurement	Number Of Valid Records	Percentage of Time (%)
<= 1	0	0
2	99	0.2
3	515	1.0
4	178	0.3
5	532	1.0
6	1280	2.4
7	3653	7.0
8	46299	88.1

Table 26: Distribution of Qualified Wind Data in Terms of the Nameplate Capacity (Scenario G)

Capacity (MW)	Number Of Valid Records	Percentage of Time (%)
[0 - 100)	0	0
[100 - 200)	585	1.1
[200 - 300)	46	0.1
[300 - 400)	102	0.2
[400 - 500)	0	0.0
[500 - 600)	150	0.3
[600 - 700)	456	0.9
[700 - 800)	0	0.0
[800 - 900)	0	0.0
[900 - 1000)	196	0.4
[1000 - 1100)	1508	2.9
[1100 - 1200)	0	0.0
[1200 - 1300)	48	0.1
[1300 - 1400)	2174	4.1
[1400 - 1500)	47291	90.0

Table 27: 10-Minute Normalized Fluctuations for Scenario B as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
3.85	2.97	10.00	-0.28	0.75	1.13	16.18	-0.55	0.62	-6.38
14.60	2.92	20.00	10.00	2.07	2.45	29.92	-1.60	1.38	-12.07
24.86	2.93	30.00	20.00	2.65	2.92	31.81	-2.26	1.99	-17.87
34.93	2.89	40.00	30.00	2.68	2.94	26.94	-2.45	2.32	-18.31
44.91	2.90	50.00	40.00	2.96	3.16	28.15	-2.75	2.55	-20.24
55.07	2.91	60.00	50.00	3.07	2.95	26.50	-2.98	2.62	-16.97
65.21	2.91	70.00	60.00	2.78	3.28	31.76	-2.70	2.62	-18.08
74.89	2.91	80.00	70.00	3.17	3.16	23.10	-2.90	2.58	-21.54
85.00	2.86	90.00	80.01	2.89	2.48	14.42	-3.05	2.82	-24.78
94.93	2.40	99.99	90.00	1.02	1.17	7.90	-1.70	2.50	-27.92

Table 28: 10-Minute Normalized Fluctuations for Scenario C as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.20	2.70	10.00	-0.19	0.72	0.92	13.26	-0.57	0.54	-5.75
15.03	2.86	20.00	10.00	1.39	1.57	20.39	-1.18	1.07	-11.35
24.86	2.84	30.00	20.00	1.62	1.81	21.33	-1.38	1.36	-12.48
35.04	2.89	40.00	30.00	2.00	2.07	20.50	-1.90	1.66	-15.95
44.95	2.91	50.00	40.00	2.20	2.26	24.37	-2.06	1.84	-17.26
54.93	2.85	60.00	50.00	2.31	2.28	29.24	-2.14	1.93	-16.19
64.96	2.88	70.00	60.00	2.33	2.40	22.71	-2.20	2.02	-22.18
75.20	2.93	80.00	70.00	2.07	2.11	20.60	-2.03	1.99	-18.02
84.50	2.86	90.00	80.00	1.68	1.65	15.60	-1.93	2.23	-23.33
94.30	2.57	99.96	90.00	1.08	1.01	5.89	-1.43	1.60	-13.14

Table 29: 10-Minute Normalized Fluctuations for Scenario D as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.23	2.79	10.00	-0.10	0.58	0.69	9.69	-0.48	0.49	-4.69
14.84	2.89	20.00	10.00	1.09	1.23	17.48	-0.94	0.86	-7.04
24.84	2.90	30.00	20.00	1.51	1.46	16.27	-1.36	1.21	-11.37
34.89	2.86	40.00	30.00	1.79	1.65	16.29	-1.72	1.52	-12.55
44.83	2.93	50.00	40.00	1.90	1.73	12.93	-1.85	1.62	-13.35
54.84	2.92	60.00	50.00	1.97	2.02	21.99	-1.80	1.59	-11.92
65.10	2.90	70.00	60.00	1.91	1.97	22.54	-1.88	1.70	-14.95
75.17	2.91	80.00	70.00	1.69	1.96	19.24	-1.71	1.76	-19.43
84.57	2.81	90.00	80.00	1.33	1.45	15.11	-1.47	1.66	-18.44
93.69	2.61	99.99	90.00	0.97	0.91	8.03	-1.51	1.92	-17.23

Table 30: 1-Minute Normalized Fluctuations for Scenario B as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
3.90	2.99	10.00	-0.28	0.13	0.26	7.47	-0.12	0.21	-4.02
14.65	2.88	20.00	10.00	0.37	0.55	11.70	-0.34	0.45	-9.75
24.88	2.92	30.00	20.00	0.51	0.71	12.68	-0.48	0.60	-9.92
34.95	2.86	40.00	30.00	0.52	0.71	11.92	-0.51	0.64	-10.42
44.87	2.89	50.00	40.00	0.60	0.76	14.64	-0.58	0.71	-11.86
55.13	2.91	60.00	50.00	0.63	0.86	34.82	-0.62	0.76	-10.69
65.05	2.84	70.00	60.00	0.58	0.77	14.30	-0.57	0.73	-13.87
74.87	2.90	80.00	70.00	0.68	0.86	15.11	-0.65	0.78	-11.24
85.21	2.96	90.00	80.00	0.62	0.78	9.93	-0.64	0.88	-28.50
93.24	1.70	97.63	90.00	0.28	0.47	5.03	-0.34	0.63	-37.58

Table 31: 1-Minute Normalized Fluctuations for Scenario C as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.22	2.69	10.00	-0.14	0.13	0.22	7.52	-0.12	0.17	-5.29
15.00	2.88	20.00	10.00	0.26	0.36	8.21	-0.25	0.32	-5.50
24.91	2.86	30.00	20.00	0.30	0.42	7.13	-0.29	0.38	-7.47
35.05	2.90	40.00	30.00	0.39	0.51	11.01	-0.38	0.46	-6.81
44.91	2.88	50.00	40.00	0.42	0.54	11.98	-0.41	0.50	-12.91
55.01	2.91	60.00	50.00	0.45	0.57	10.36	-0.45	0.55	-13.08
64.97	2.90	70.00	60.00	0.47	0.61	13.58	-0.46	0.58	-15.62
75.15	2.90	80.00	70.00	0.41	0.58	17.68	-0.42	0.60	-13.37
84.50	2.89	90.00	80.00	0.38	0.48	10.64	-0.39	0.53	-14.53
94.11	2.49	99.99	90.00	0.27	0.34	3.99	-0.30	0.44	-18.94

Table 32: 1-Minute Normalized Fluctuations for Scenario D as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.22	2.79	10.00	-0.07	0.11	0.17	4.21	-0.10	0.15	-2.80
14.86	2.89	20.00	10.00	0.21	0.31	7.71	-0.20	0.27	-3.47
24.79	2.90	30.00	20.00	0.30	0.40	7.69	-0.29	0.36	-5.63
34.83	2.88	40.00	30.00	0.35	0.45	7.56	-0.35	0.44	-6.59
44.93	2.96	50.00	40.00	0.38	0.49	10.23	-0.37	0.47	-8.52
54.85	2.91	60.00	50.00	0.39	0.53	9.98	-0.38	0.48	-9.54
65.05	2.87	70.00	60.00	0.38	0.51	8.91	-0.38	0.50	-8.30
75.17	2.89	80.00	70.00	0.33	0.48	10.40	-0.33	0.46	-10.48
84.40	2.75	90.00	80.00	0.29	0.44	9.17	-0.31	0.46	-8.73
93.11	2.17	98.68	90.00	0.23	0.30	6.25	-0.26	0.42	-11.19

Table 33: 10-Minute Normalized Fluctuations for Scenario E as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.28	2.71	10.00	0.00	0.71	0.85	15.20	-0.57	0.56	-4.80
15.08	2.92	20.00	10.00	1.33	1.35	12.51	-1.20	1.10	-10.91
25.12	2.88	30.00	20.00	1.46	1.48	16.58	-1.34	1.30	-14.16
34.84	2.90	40.00	30.00	1.58	1.49	12.09	-1.56	1.46	-19.07
44.90	2.90	50.00	40.00	1.77	1.68	17.45	-1.74	1.49	-16.42
54.85	2.96	60.00	50.00	1.98	1.78	13.60	-1.92	1.66	-15.15
64.86	2.86	69.99	60.00	1.94	1.80	18.01	-1.89	1.66	-14.24
74.73	2.87	80.00	70.00	1.86	2.04	18.14	-1.88	1.88	-14.19
84.58	2.81	89.99	80.00	1.79	1.76	14.33	-1.94	1.82	-13.40
94.01	2.83	100.00	90.00	1.24	1.23	8.55	-1.68	1.76	-13.53

Table 34: 10-Minute Normalized Fluctuations for Scenario F as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.25	2.78	10.00	0.00	0.66	0.83	13.20	-0.53	0.53	-4.82
14.83	2.85	20.00	10.00	1.35	1.45	18.66	-1.16	1.04	-10.43
24.92	2.91	30.00	20.00	1.78	1.71	16.08	-1.67	1.48	-10.54
34.89	2.89	40.00	30.00	2.02	2.01	18.37	-1.91	1.70	-12.92
44.83	2.90	49.99	40.00	2.22	2.18	24.06	-2.08	1.87	-16.25
54.85	2.86	60.00	50.00	2.39	2.41	22.38	-2.18	2.01	-14.94
65.02	2.90	69.99	60.02	2.51	2.44	21.21	-2.43	2.18	-19.92
74.93	2.87	80.00	70.00	2.47	2.73	23.00	-2.27	2.21	-18.65
85.30	2.96	90.00	80.00	1.81	1.99	15.90	-2.03	2.13	-22.39
93.75	2.57	100.00	90.00	0.73	0.81	7.47	-1.30	2.25	-21.84

Table 35: 10-Minute Normalized Fluctuations for Scenario G as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.17	2.90	10.00	0.00	0.68	0.91	13.87	-0.52	0.56	-4.75
14.61	2.90	20.00	10.00	1.63	1.79	17.98	-1.32	1.15	-7.93
24.82	2.95	30.00	20.00	2.39	2.45	24.68	-2.04	1.78	-13.71
34.91	2.87	40.00	30.00	2.64	2.55	23.53	-2.41	2.21	-18.04
44.92	2.87	50.00	40.00	2.82	2.90	29.89	-2.61	2.41	-18.33
55.02	2.93	60.00	50.01	2.79	2.67	29.76	-2.90	2.59	-21.33
65.10	2.89	70.00	60.00	2.78	3.35	27.98	-2.56	2.58	-26.30
75.10	2.94	79.99	70.00	2.76	3.14	26.53	-2.49	2.56	-28.18
85.58	2.89	90.00	80.00	1.36	1.59	16.24	-1.81	2.41	-34.54
93.65	2.55	100.00	90.00	0.67	0.73	8.45	-1.18	2.67	-33.53

Table 36: 1-Minute Normalized Fluctuations for Scenario E as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.28	2.70	10.00	0.00	0.14	0.22	8.76	-0.12	0.18	-3.58
15.09	2.93	20.00	10.00	0.27	0.39	8.57	-0.26	0.36	-7.14
25.14	2.88	30.00	20.00	0.29	0.42	11.19	-0.28	0.41	-11.71
34.84	2.89	40.00	30.00	0.32	0.46	8.77	-0.32	0.44	-7.15
44.91	2.90	50.00	40.00	0.36	0.48	7.75	-0.36	0.47	-8.33
54.87	2.96	60.00	50.00	0.40	0.54	8.97	-0.40	0.53	-10.60
64.85	2.85	70.00	60.00	0.39	0.53	7.04	-0.39	0.52	-7.75
74.70	2.86	80.00	70.00	0.38	0.57	9.33	-0.39	0.55	-9.54
84.59	2.80	90.00	80.00	0.38	0.55	9.65	-0.40	0.56	-6.28
93.82	2.69	99.55	90.00	0.28	0.40	5.72	-0.32	0.48	-5.60

Table 37: 1-Minute Normalized Fluctuations for Scenario F as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.24	2.77	10.00	0.00	0.12	0.20	5.49	-0.11	0.17	-2.82
14.82	2.84	20.00	10.00	0.27	0.39	7.87	-0.25	0.34	-5.92
24.93	2.91	30.00	20.00	0.36	0.50	8.91	-0.35	0.47	-6.63
34.89	2.89	40.00	30.00	0.40	0.56	8.26	-0.39	0.52	-7.38
44.89	2.92	50.00	40.00	0.44	0.63	10.71	-0.44	0.60	-9.91
54.82	2.89	60.00	50.00	0.47	0.67	10.17	-0.46	0.62	-10.18
65.08	2.93	70.00	60.00	0.49	0.68	10.47	-0.48	0.66	-10.51
74.87	2.88	80.00	70.00	0.48	0.73	12.93	-0.46	0.65	-10.46
85.57	2.88	90.00	80.00	0.33	0.57	12.95	-0.36	0.61	-12.07
92.80	1.99	99.55	90.00	0.16	0.30	6.75	-0.20	0.51	-12.70

Table 38: 1-Minute Normalized Fluctuations for Scenario G as a Percentage of its Capacity

Power	Sd.	Max	Min	Avg. Inc.	Sd. Inc.	Max. Inc.	Avg. Dec.	Sd. Dec	Max. Dec.
5.16	2.89	10.00	0.00	0.13	0.23	7.39	-0.12	0.18	-5.56
14.64	2.90	20.00	10.00	0.31	0.48	17.84	-0.29	0.40	-7.38
24.85	2.93	30.00	20.00	0.46	0.68	12.24	-0.44	0.60	-10.67
34.92	2.87	40.00	30.00	0.53	0.73	11.82	-0.52	0.72	-12.06
44.89	2.89	50.00	40.00	0.55	0.81	14.46	-0.54	0.75	-11.17
55.06	2.91	60.00	50.00	0.58	0.84	15.15	-0.59	0.82	-15.99
65.05	2.86	70.00	60.00	0.53	0.82	13.78	-0.52	0.77	-19.98
75.22	2.88	80.00	70.00	0.54	0.90	16.03	-0.53	0.82	-14.58
85.59	2.86	90.00	80.00	0.27	0.52	12.94	-0.30	0.62	-17.41
92.91	2.05	99.87	90.00	0.15	0.28	7.94	-0.19	0.49	-16.71

Table 39: Frequency Distribution of Power for Scenario A

Power (% Capacity)	Valid Records	Percentage of Time
[0-10)	18390	35.0
[10-20)	5271	10.0
[20-30)	3498	6.7
[30-40)	2920	5.6
[40-50)	2524	4.8
[50-60)	2511	4.8
[60-70)	2627	5.0
[70-80)	3572	6.8
[80-90)	7698	14.6
[90-100]	3545	6.7

Table 40: Frequency Distribution of Power for Scenario B

Power (% Capacity)	Valid Records	Percentage of Time
[0-10)	14279	27.2
[10-20)	6506	12.4
[20-30)	4836	9.2
[30-40)	4538	8.6
[40-50)	4083	7.8
[50-60)	3782	7.2
[60-70)	4258	8.1
[70-80)	3323	6.3
[80-90)	3340	6.4
[90-100]	3611	6.9

Table 41: Frequency Distribution of Power for Scenario C

Power (% Capacity)	Valid Records	Percentage of Time
[0-10)	7966	15.2
[10-20)	7110	13.5
[20-30)	7732	14.7
[30-40)	6204	11.8
[40-50)	5453	10.4
[50-60)	5026	9.6
[60-70)	4558	8.7
[70-80)	4563	8.7
[80-90)	2840	5.4
[90-100]	1104	2.1

Table 42: Frequency Distribution of Power for Scenario D

Power (% Capacity)	Valid Records	Percentage of Time
[0-10)	9032	17.2
[10-20)	8598	16.4
[20-30)	6542	12.4
[30-40)	5748	10.9
[40-50)	5012	9.5
[50-60)	4468	8.5
[60-70)	4355	8.3
[70-80)	4944	9.4
[80-90)	3292	6.3
[90-100]	565	1.1

Table 43: Frequency Distribution of Power for Scenario E

Power (% Capacity)	Valid Records	Percentage of Time
[0-10)	7656	14.6
[10-20)	7246	13.8
[20-30)	8700	16.6
[30-40)	7751	14.7
[40-50)	6509	12.4
[50-60)	4884	9.3
[60-70)	4557	8.7
[70-80)	3066	5.8
[80-90)	1751	3.3
[90-100]	436	0.8

Table 44: Frequency Distribution of Power for Scenario F

Power (% Capacity)	Valid Records	Percentage of Time
[0-10)	9855	18.8
[10-20)	7817	14.9
[20-30)	6337	12.1
[30-40)	5773	11.0
[40-50)	4703	8.9
[50-60)	4089	7.8
[60-70)	4070	7.7
[70-80)	3893	7.4
[80-90)	4605	8.8
[90-100]	1414	2.7

Table 45: Frequency Distribution of Power for Scenario G

Power (% Capacity)	Valid Records	Percentage of Time
[0-10)	11665	22.2
[10-20)	7068	13.4
[20-30)	4933	9.4
[30-40)	4411	8.4
[40-50)	4061	7.7
[50-60)	3887	7.4
[60-70)	3922	7.5
[70-80)	4132	7.9
[80-90)	6653	12.7
[90-100]	1824	3.5

12 Appendix B: Additional Results for Electric System Impact

Table 46: Magnitude of Short Term Wind and Net Demand Variability of Scenarios A, B, C, and D for Three Time Frames

Item	Index	Scenario	1-minute	Intra 60-minute	Inter 60-minute
Net Demand	Positive Change	A	11	201	189
		B	12	201	194
		C	16	199	210
		D	25	202	273
	Negative Change	A	-10	-240	-214
		B	-11	-228	-214
		C	-15	-223	-220
		D	-24	-222	-281
Wind	Positive Change	A	6	14	65
		B	8	23	88
		C	11	34	132
		D	20	61	224
	Negative Change	A	-6	-13	-54
		B	-7	-20	-79
		C	-11	-30	-118
		D	-19	-58	-211

Table 47: Magnitude of Short Term Wind and Net Demand Variability of Scenarios E, F, and G for Three Time Frames

Item	Index	Scenario	1-minute	Intra 60-minute	Inter 60-minute
Net Demand	Positive Change	E	27	208	277
		F	31	200	308
		G	34	210	322
	Negative Change	E	-26	-221	-269
		F	-30	-220	-308
		G	-33	-227	-344
Wind	Positive Change	E	22	65	216
		F	25	82	268
		G	29	96	289
	Negative Change	E	-22	-60	-216
		F	-25	-73	-254
		G	-28	-88	-296

Table 48: System Dispatch Time Simulation CPS2 Ratings for all Wind Development Scenarios and Varying Forecasting Methods

Scenario	Wind Forecast Method	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07
Historical Actual		0.863	0.850	0.938	0.951	0.953	0.925	0.942	0.933	0.952	0.918	0.956	0.944
Historical Simulated	Persistent	0.861	0.865	0.966	0.956	0.967	0.939	0.935	0.925	0.953	0.920	0.951	0.943
A**	Persistent*	0.961	0.931	0.995	0.988	0.987	0.981	0.968	0.969	0.953	0.920	0.951	0.989
	Pers. Ramp	0.950	0.924	0.992	0.984	0.984	0.976	0.960	0.959	0.951	0.913	0.947	0.990
	Perfect	0.961	0.933	0.996	0.988	0.987	0.988	0.975	0.976	0.952	0.922	0.953	0.990
B**	Persistent	0.955	0.918	0.98	0.986	0.973	0.968	0.955	0.954	0.933	0.912	0.955	0.987
	Pers. Ramp	0.935	0.895	0.951	0.976	0.953	0.930	0.924	0.921	0.917	0.876	0.924	0.974
	Perfect	0.957	0.932	0.991	0.989	0.981	0.985	0.97	0.974	0.943	0.926	0.962	0.993
C**	Persistent	0.941	0.899	0.943	0.961	0.947	0.927	0.928	0.932	0.918	0.875	0.955	0.946
	Pers. Ramp	0.921	0.842	0.898	0.908	0.901	0.854	0.862	0.863	0.863	0.805	0.895	0.886
	Perfect	0.954	0.922	0.977	0.980	0.969	0.972	0.963	0.96	0.925	0.906	0.982	0.985
D**	Persistent	0.852	0.769	0.838	0.870	0.861	0.791	0.788	0.791	0.813	0.739	0.869	0.832
	Pers. Ramp	0.779	0.691	0.764	0.803	0.736	0.710	0.686	0.704	0.728	0.646	0.791	0.733
	Perfect	0.905	0.857	0.923	0.942	0.934	0.907	0.889	0.896	0.882	0.844	0.939	0.923
E**	Persistent	0.841	0.762	0.842	0.851	0.815	0.804	0.768	0.807	0.814	0.762	0.831	0.811
	Pers. Ramp	0.771	0.696	0.762	0.754	0.703	0.692	0.648	0.691	0.705	0.689	0.765	0.686
	Perfect	0.906	0.860	0.921	0.926	0.949	0.902	0.886	0.906	0.883	0.859	0.923	0.932
F**	Persistent	0.811	0.724	0.824	0.832	0.785	0.747	0.727	0.728	0.796	0.703	0.758	0.775
	Pers. Ramp	0.741	0.648	0.747	0.765	0.664	0.634	0.629	0.630	0.712	0.605	0.687	0.646
	Perfect	0.871	0.836	0.899	0.927	0.918	0.880	0.859	0.861	0.875	0.814	0.881	0.896
G**	Persistent	0.802	0.691	0.784	0.797	0.748	0.730	0.737	0.732	0.748	0.678	0.764	0.720
	Pers. Ramp	0.724	0.607	0.701	0.728	0.635	0.619	0.644	0.645	0.654	0.565	0.703	0.611
	Perfect	0.869	0.813	0.874	0.891	0.875	0.859	0.851	0.861	0.849	0.794	0.889	0.853

*Scenario A with Persistent Forecasting is referred to as the benchmark scenario

**Time simulations for Scenarios A through G were performed with current regulating reserve range